AR80

STRATEGIC GROWTH

Annual Report 2004

Crescent Point
ENERGY TRUST

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NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of unitholders of Crescent Point Energy Trust will be held on Tuesday, May 31, 2005 at 10:00 a.m. in the Riverview Room A/B of The International Hotel of Calgary, 220 – 4th Avenue SW, Calgary, Alberta. Unitholders are encouraged to attend the meeting and those unable to do so are urged to complete, sign and return their form of proxy mailed with this report.

ORGANIZATION DEFINITION

Throughout the Annual Report, Crescent Point Energy Trust and its subsidiaries and related entities are referred to as "Crescent Point", or the "Trust".

VOLUME REPORTING

Barrel of oil equivalent ("boe") figures for the periods presented throughout this report are expressed at a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. This conversion ratio approximates relative heating values, and is the generally accepted ratio used by Canadian oil and gas companies, oil and gas trusts and investment analysts.

NATIONAL INSTRUMENT 51-101

All reserves quoted are defined under National Instrument 51-101 ("NI 51-101") guidelines. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate".

PLAN OF ARRANGEMENT

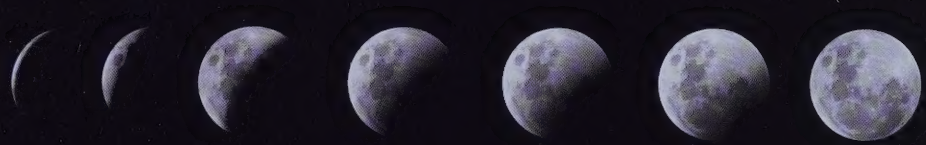
Crescent Point Energy Ltd. ("Crescent Point Energy" or the "Corporation") completed a strategic merger whereby it acquired Tappit Resources Ltd. ("Tappit") and converted into an oil and gas income trust through a Plan of Arrangement (the "Plan"). In addition, the shareholders of Crescent Point Energy and Tappit received shares in StarPoint Energy Ltd. ("StarPoint"), a separate, publicly listed, exploration and production company. The special meeting of the shareholders approving the Plan was held on August 21, 2003. The effective date for the transaction was September 5, 2003.

CAPITAL STRUCTURE

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

FORWARD-LOOKING STATEMENTS

Certain information regarding the Trust contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements.



TRUST PROFILE

Crescent Point Energy Trust is a conventional oil and gas income trust with assets strategically focused in properties comprised of high quality, long life, operated, light oil and natural gas reserves in western Canada.

Crescent Point strives to create sustainable, value-added growth in reserves, production and cash flow through the execution of management's integrated strategy of acquiring, exploiting and developing high quality, long life, light oil and natural gas properties.

The Trust continually investigates and searches out producing properties that will result in meaningful reserve and production additions. We focus capital on higher-quality, longer-life reservoirs in proven growth areas that offer existing infrastructure, low cost drilling, multi-zone potential and year round access. Our goal is to acquire operational control of those properties that we believe offer significant exploitation and development potential.

The Trust develops its properties through a detailed technical analysis of information including reservoir characteristics, original oil or gas in place, recovery factors and the applicability of enhanced recovery techniques. Our goal is to increase reserves and production in a cost effective manner through a number of techniques including drilling infill and step-out wells, recompleting existing wells and implementing waterflood or pressure support schemes.

Crescent Point's units trade on the Toronto Stock Exchange under the symbol CPG.UN.

STRATEGIC GROWTH

In 2004, Crescent Point increased reserves, production and cash flow through a combination of development and exploitation of the Trust's light oil and natural gas properties and a series of high quality, light oil and natural gas acquisitions.

Crescent Point's proved plus probable reserves increased by 42 percent, production increased by 70 percent and cash flow increased by 91 percent. This growth was achieved while maintaining the Trust's focused asset base, strong balance sheet and high quality reserve base.

The Trust has an inventory of large oil and gas in place pools with the potential to double the Trust's proven reserves over the next three to five years through water flood optimization, infill drilling and improved production performance.

In 2005, Crescent Point will continue to focus on:

- acquiring high quality, long-life reserves and production in the Western Canadian Sedimentary Basin;
- exploiting its high quality reserve base through development drilling and field optimization activities to maintain production, cash flow and distributions; and
- using the Trust's in-house technical expertise to increase Crescent Point's low risk development drilling inventory within our core properties at Manor, Tatagwa, Innes, Little Bow, Sounding Lake, John Lake and Doe.

FINANCIAL AND OPERATING HIGHLIGHTS

Years ended December 31 ($000s except Trust units, per Trust unit and per boe amounts)	2004	2003 [4]	% Change
Financial			
Gross revenue	155,299	76,792	102
Cash flow from operations	69,828	36,626	91
Per unit - diluted	2.49	1.99	25
Net income	30,659	9,134	236
Per unit - diluted	1.09	0.50	118
Cash distributions	53,877	11,697	361
Per unit	2.04	0.68	200
Payout ratio (percent) [1]	77	32	45
Per unit - diluted (percent) [1]	82	34	48
Capital expenditures and corporate acquisitions, net [2]	195,354	129,301	51
Net debt [3]	95,360	38,417	148
Trust units outstanding (MM)			
Units	29.3	19.3	52
Exchangeable Shares	1.3	1.9	(32)
Weighted average Trust units outstanding (MM)			
Basic (2003 - combined A&B shares)	27.8	18.4	51
Diluted	28.1	18.4	53
Operating			
Average daily production			
Crude oil and NGLs (bbl/d)	6,815	4,536	50
Natural gas (mcf/d)	16,733	6,738	148
Total (boe/d)	9,604	5,659	70
Average product prices			
Crude oil and NGLs ($/bbl)	46.40	37.05	25
Financial instruments – realized losses ($/bbl)	(7.42)	(1.48)	(401)
	38.98	35.57	10
Natural gas ($/mcf)	6.46	6.28	3
Financial instruments - realized losses ($/mcf)	(0.06)	(0.11)	45
	6.40	6.17	4
Netback ($/boe)	23.00	22.46	2
Wells drilled			
Gross	38.0	27.0	41
Net	31.8	19.0	67
Success rate (percent)	95	95	-

1) Crescent Point converted to a trust on September 5, 2003 and began paying distributions effective with the month of September 2003. The Trust's payout ratio for the period September 5, 2003 to December 31, 2003 was 76 percent on an overall basis and 84 percent on a per unit-diluted basis.
2) The capital expenditures and corporate acquisitions include the purchase price of corporate acquisitions (including the working capital deficiency and debt acquired). These amounts differ from the amounts allocated to property, plant and equipment as there were allocations made to goodwill, other assets and liabilities.
3) Net debt is debt net of the working capital deficiency excluding the risk management liability.
4) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

PRESIDENT'S LETTER TO UNITHOLDERS

Crescent Point's business plan is to create sustainable value-added growth in reserves, production and cash flow through the execution of management's integrated strategy of acquiring, exploiting and developing high quality, long life, light oil and natural gas properties.

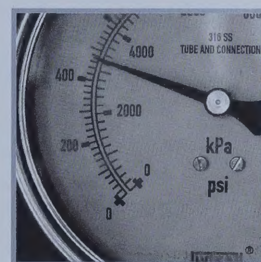
Crescent Point's proved plus probable reserves increased by 42 percent, production increased by 70 percent and cash flow increased by 91 percent. This growth was achieved while maintaining the Trust's focused asset base, strong balance sheet and high quality reserve base.

2004 HIGHLIGHTS

- Crescent Point completed three major acquisitions and five consolidation acquisitions for $166.2 million which added approximately 3,350 boe/d of production and 8.3 mmboe proved and 11.2 mmboe proved plus probable reserves.

- The Trust's acquisitions and successful drilling program increased average daily production by 70 percent from 5,659 boe/d in 2003 to 9,604 boe/d in 2004.

- Crescent Point completed two bought deal equity financings of 8,150,000 units for gross proceeds of $110.7 million.



- Crescent Point increased its reserves from 18.4 mmboe proved and 24.1 mmboe proved plus probable reserves at the end of 2003, to 25.7 mmboe proved and 34.3 mmboe proved plus probable reserves at the end of 2004, as independently evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ") under NI 51-101. This represents an increase of 40 percent for proved reserves and 42 percent for proved plus probable reserves. Crescent Point maintained its reserve life index of 6.8 years proved and 9.1 years proved plus probable, based on the Trust's 2005 production forecast of 10,350 boe/d.

- The Trust drilled 38 gross wells and 31.8 net wells with a success rate of 95 percent.

- Crescent Point made two new pool discoveries at Manor-Auburnton in southeast Saskatchewan which have added an internally estimated 4.9 mmbbl of original oil in place along with over 1,000 bbl/d of initial flush production in the fourth quarter of 2004.

- The Trust's finding, development and acquisition costs for 2004, excluding future development costs, were $17.76 per proved boe and $13.99 per proved plus probable boe of reserves. The Trust's rolling four-year average for finding, development and acquisition costs (excluding future development costs) for proved plus probable reserves was $9.38 per boe. The Trust's finding, development and acquisitions costs for 2004, including future development costs, were $18.29 per proved boe and $14.39 per proved plus probable boe.

- Crescent Point increased cash flow from operations by 91 percent from $36.6 million or $1.99 per unit-diluted in 2003 to $69.8 million or $2.49 per unit-diluted in 2004.

- Crescent Point maintained consistent monthly distributions of $0.17 per unit, totaling $2.04 per unit for 2004 and representing a diluted payout ratio of 82 percent.

- Crescent Point maintained an excellent balance sheet throughout the year which positions the Trust for continued growth in 2005 and beyond. The Trust's credit facility was increased to $135 million and syndicated with two additional Canadian chartered banks.

- The Trust has identified more than 130 low risk infill development drilling locations with more than 5,500 boe/d of risked production additions.

- Crescent Point appointed Mr. Gerald A. Romanzin to the Board of Directors, Mr. Greg Tisdale to Chief Financial Officer, Ms. Tamara MacDonald to Land Manager, and promoted Mr. David Balutis to Vice President, Geosciences and Mr. Scott Saxberg to Chief Executive Officer.

2005 MARKET GUIDANCE

Crescent Point has the three key attributes of a successful Trust; a proven management group and Board of Directors, an excellent balance sheet and a high quality, long life reserve base.

The Trust has a high quality, predictable production, reserve and cash flow base focused in large oil and gas in place properties. Each of these properties is characterized by high working interests, is operated by Crescent Point and has significant development upside.

During 2004, Crescent Point continued to expand the Trust's development drilling inventory by completing eight strategic acquisitions and adding more

than 30 low risk development locations. Crescent Point now has an inventory of more than 130 low risk development locations in its core areas, which will provide for sustainable production and distributions through 2005 and beyond.

Crescent Point continues to lock in commodity price swaps for 2005 through 2007 at attractive crude oil pricing parameters to reduce risk on distribution levels.

Crescent Point has had an excellent start to 2005, with a successful first quarter drilling program, and is projecting average daily production for 2005 of 10,350 boe/d.

Crescent Point has maintained an excellent balance sheet with approximately $40 million of unutilized credit lines and projected net debt of less than 1.0 times projected annual cash flow.

In 2005, Crescent Point is projecting to maintain its 10,350 boe/d of production, with capital expenditures of approximately $26 million for drilling, optimization, land and seismic. Estimates for 2005 are as follows:

Production	
Oil and NGLs (bbl/d)	7,850
Natural gas (mcf/d)	15,000
Total (boe/d)	10,350
Cash flow ($000s)	82,000
Cash flow per unit-diluted ($)	2.55
Cash distributions per unit ($)	2.04
Payout ratio - per unit-diluted (percent)	80
Capital expenditures ($000s) (1)	26,000
Wells drilled, net	29.0
Pricing	
Crude oil - WTI ($US/bbl)	40.00
Crude oil - Corporate ($Cdn/bbl)	50.00
Natural gas - AECO ($US/GJ)	5.20
Natural gas - Corporate ($Cdn/GJ)	6.50
Exchange rate ($Cdn/$US)	0.80

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

Crescent Point's management believes the Trust is well positioned for tremendous growth through 2005 with its high quality reserve base, low risk development inventory, excellent balance sheet and hedging program.

I would like to thank our Board of Directors for their continued support and guidance as well as Crescent Point's employees for their hard work and dedication to deliver outstanding results over the past year.

On behalf of the Board of Directors,

Scott Saxberg
President and Chief Executive Officer
March 11, 2005

Production - by quarter

Note:
(e) estimate

Cash Flow - by quarter

■ Reorganization Costs

Note:

1 The cash flow of $6.1 million for Q3 2003 is net of reorganization costs of $4.9 million.

2 The cash flow of $12.0 million for Q4 2003 is net of reorganization costs of $300,000.

(e) estimate

Reserves

■ Total Proved
■ Total Proved Plus Probable

Finding, Development and Acquisition Costs

■ Total Proved
■ Total Proved Plus Probable
— 4 Year Average Total Proved Plus Probable

ACQUISITION AND OPERATIONS REVIEW

Crescent Point strives to create sustainable, value-added growth in production, reserves and cash flow through the execution of management's integrated strategy of acquiring, exploiting, developing and optimizing its high quality, long life, light oil and natural gas properties.

Consistent with the Trust's business strategy, value-added growth in production, reserves and cash flow was achieved in 2004. Crescent Point's average daily production increased 70 percent from 5,659 boe/d in 2003 to 9,604 boe/d in 2004. The Trust increased its reserve base from 18.4 mmboe proved and 24.1 mmboe proved plus probable reserves at the end of 2003, to 25.7 mmboe proved and 34.3 mmboe proved plus probable reserves at the end of 2004, as independently evaluated by GLJ.

The Trust's finding, development and acquisition costs for 2004, excluding future development costs, were $17.76 per proved boe and $13.99 per proved plus probable boe of reserves. The Trust's rolling four-year average for finding, development and acquisition costs (excluding future development costs) for proved plus probable reserves was $9.38 per boe. The Trust's finding, development and acquisition costs for 2004, including future development costs, were $18.29 per proved boe and $14.39 per proved plus probable boe.

During 2004, the Trust closed three major acquisitions and five consolidation acquisitions for a total purchase price of $166.2 million. The acquisitions added 3,350 boe/d of production and 8.3 mmboe proved and 11.2 mmboe proved plus probable reserves.

The Trust drilled 38 (31.8 net) wells in 2004 with a success rate of 95 percent. The majority of the wells were drilled in southeast Saskatchewan (27 wells), with 10 wells drilled in northeast British Columbia and west Peace River Arch, Alberta and one well in south central Alberta.

Consistent with the business strategy of optimizing the Trust's high quality, long life light oil and natural gas reserves, several value-added initiatives were completed in 2004. The Trust continued to increase pool recovery factors through its improved reservoir recovery development strategy. The Trust continued to optimize waterflood operations at the Little Bow, Sounding Lake and Tatagwa properties, commenced pressure surveys on the Doe property and expanded facilities at the Tatagwa Unit to accommodate increased fluid handling. The combination of these optimization activities allowed the Trust to replace 2004 production by approximately 73 percent through technical and development revisions.

Review of Core Properties

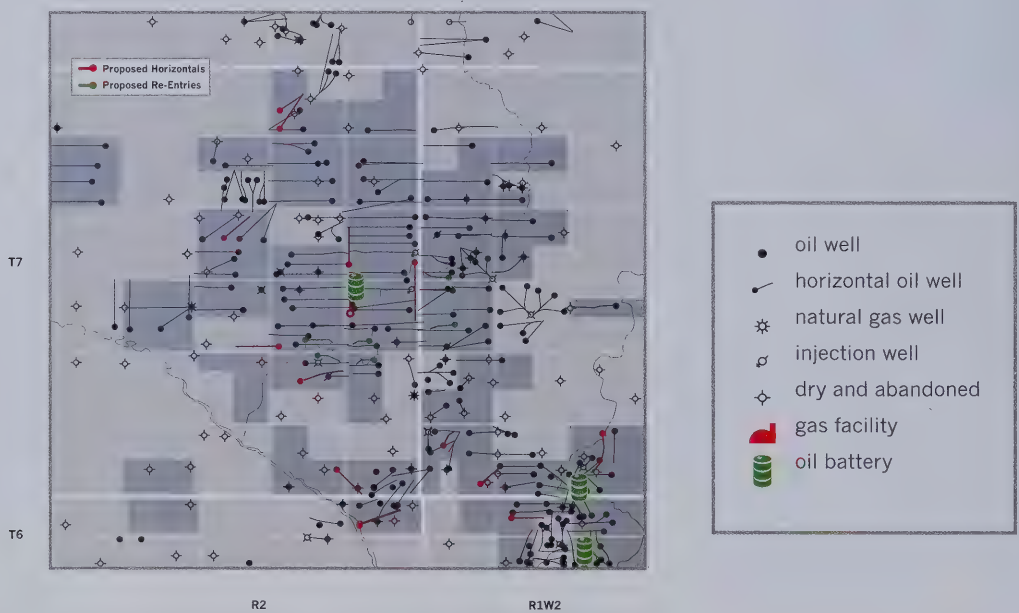
Southeast Saskatchewan

MANOR

The Manor property is comprised of five large oil in place pools: the Manor Lower Watrous-Alida, Queensdale North Alida, Wildwood Alida and two new Alida pool discoveries in the Manor-Auburnton area. The Lower Watrous-Alida pool has more than 95 mmbbl of original oil in place. The Queensdale North Alida and Wildwood Alida pools have over 18 mmbbl and 10 mmbbl of original oil in place, respectively, and the two new pool discoveries at Auburnton have an internally estimated 4.9 mmbbl of original oil in place combined. Recovery factors are less than 16.0 percent from the Manor Lower Watrous-Alida and Wildwood Alida pools, while 8.7 percent has been recovered from the Queensdale North Alida pool. Crescent Point holds an average 97 percent, operated working interest in the area.

The Manor property exited 2004 with average daily production of 3,100 bbl/d of 36° API light oil and 600 mcf/d of natural gas production. Utilizing the Trust's proprietary 3D seismic program which covers the five pools in the Manor area, the Trust drilled 14 (12.2 net) operated, horizontal light oil wells and one (1.0 net) service well, achieving a success rate of 100 percent. Two new pool discoveries in the Auburnton area of Manor added over 1,000 bbl/d of initial flush production in the fourth quarter. Construction of gathering facilities to accommodate increased fluid handling commenced in December. Crescent Point has identified more than 23 development drilling locations remaining within the Manor area, of which up to ten locations are planned to be drilled in 2005.

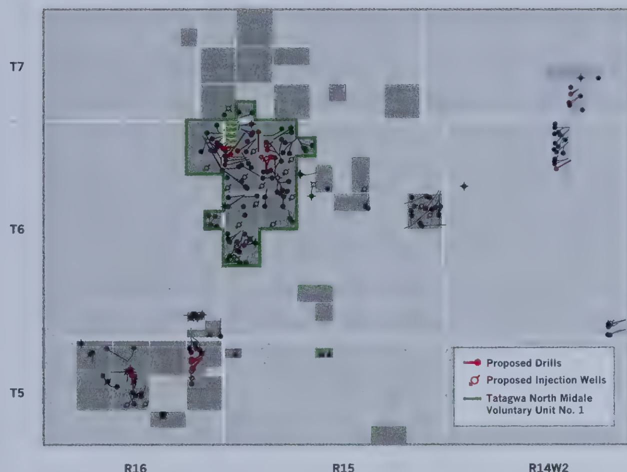
The Trust's oil production at the time of the first Manor acquisition in 2002 was approximately 575 bbl/d. The five-fold increase in production since 2002 illustrates the tremendous growth potential offered by these high quality, long life, light oil assets as well as the property consolidation opportunities in the area.



TATAGWA

Unit

Crescent Point owns a 70 percent, operated working interest in the Tatagwa North Midale Voluntary Unit No. 1 (the "Unit"). The North Midale pool has an estimated 157 mmbbl of original oil in place, of which 2.9 percent has been recovered to date. Similar pools to the east of the property have estimated recoveries of over 13 percent. In January 2003, a large scale waterflood was implemented, including the installation of central water injection facilities. Currently, there are 44 producing oil wells supported by water injection from 15 wells.



During 2004, the Trust drilled three (2.1 net) successful horizontal oil wells as well as two (1.4 net) injection wells, optimizing pool sweep efficiencies and recoveries. Central facilities were expanded to accommodate increased fluid handling. The Trust's interest production from the Unit averaged 1,015 bbl/d in December 2004. For 2005, the Trust plans to drill up to four additional horizontal wells and three vertical injection wells.

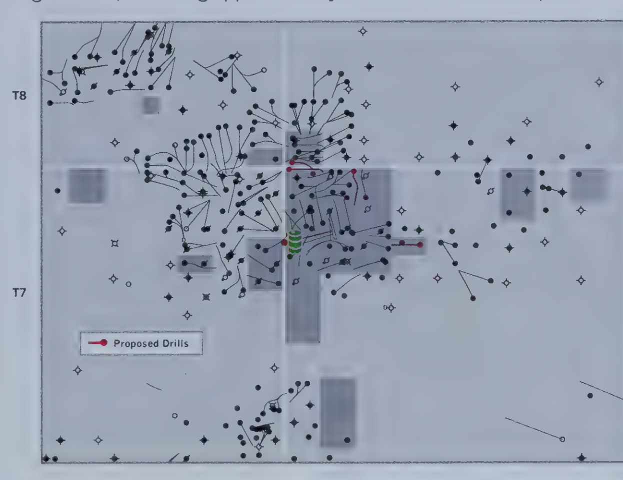
At Tatagwa, Crescent Point has had positive technical reserve revisions year over year. In July 2003, the ultimate recovery factor of oil in place was forecast to be 6.8 percent. This increased to 7.7 percent in January 2004 and then to 9.1 percent in January 2005. Overall, the Trust's reserves increased by 2.5 mmbbl in an 18 month period. This demonstrates the Trust's ability to execute its strategy of continuously increasing reserves and value from large oil in place reservoirs through its operating expertise.

Non Unit

In August 2004, the Trust acquired approximately 550 bbl/d of non-Unit oil production immediately adjacent to its Unit interests, adding at least fourteen drill locations to its inventory in the Tatagwa south, Lougheed and Weyburn areas and access to over 50 mmbbls of additional original oil in place. The Trust plans to drill up to five of these locations in 2005.

INNES

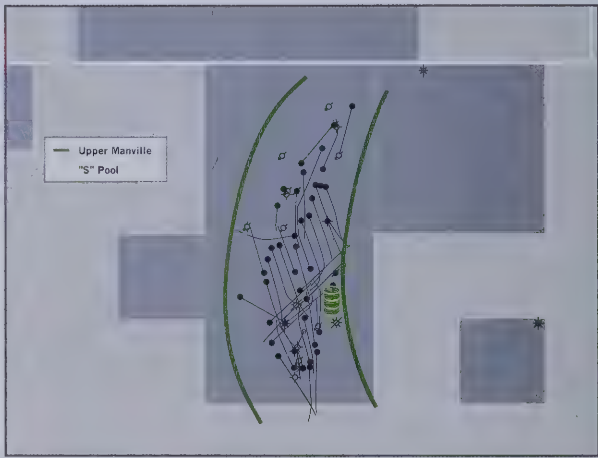
In August 2004, the Trust acquired approximately 900 bbl/d of oil and 300 mcf/d of natural gas production in its core southeast Saskatchewan operating corridor, including approximately 450 boe/d of interest production in the operated Innes area. Production is derived from the high quality, light oil, high netback Frobisher formation estimated to contain 40 mmbbl of original oil in place on interest lands. Approximately 34.0 percent of the oil has been recovered with offsetting analogous reservoirs estimated to have recovery factors of 45.0 percent of oil in place. At least eight drilling locations were identified on interest lands, including one (0.5 net) grass root horizontal well and one (0.5 net) re-entry horizontal well that were drilled and completed in late 2004. An additional two drills are planned for the first quarter of 2005.



In all, the Trust plans to drill up to 24 (23.4 net) wells in southeast Saskatchewan in 2005.

South/Central Alberta

LITTLE BOW



The Trust holds a 100 percent, operated working interest in the Little Bow Upper Mannville "S" pool, which has approximately 18 mmbbl of original oil in place together with a four bcf gas cap, and a partially active bottom aquifer. To date, approximately 31.0 percent of the oil in place has been recovered while similar analogous pools have recovered up to 50.0 percent of the oil in place. Oil production is gathered to a central battery and transferred into the Bow River pipeline system while conserved solution gas is gathered to the non-operated Travers gas plant for processing.

The 2004 exit production for the Little Bow property was approximately 785 bbl/d of operated medium gravity crude oil and 775 mcf/d of natural gas, for total interest production of approximately 915 boe/d.

During 2004, the Trust optimized water injection to improve pool recoveries, and optimized gas compression to reduce down time and operating costs. In addition, two successful reperforations were completed in previously suspended wells adding further production. During 2005, the Trust plans to recomplete two suspended wells and drill up to two locations.

SOUNDING LAKE

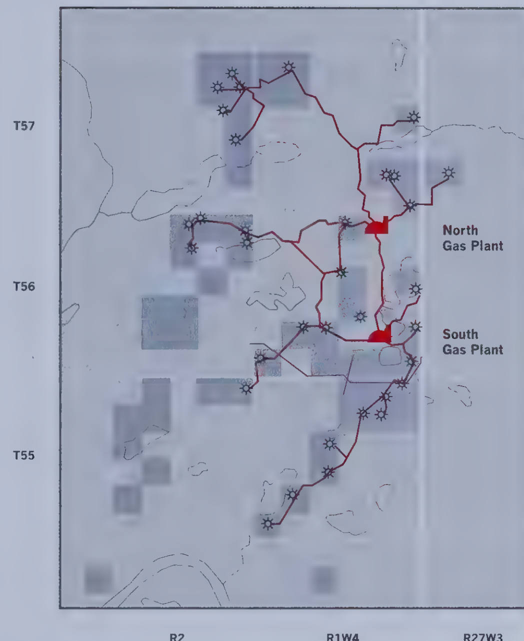
The Sounding Lake property provides a low decline, predictable reserve base, with large original oil in place of more than 18 mmbbl in the Cummings "A" pool and more than 19 mmbbl in the Dina G4G Pool. Crescent Point holds a 100 percent, operated working interest in the Cummings "A" Unit waterflood, and various interests in several non-unit Dina G4G and Sparky pool oil wells. Oil production is shipped through the Hamilton Lake pipeline to market.

In November 2004, the Trust acquired additional interests in the area representing approximately 370 boe/d. Several recompletion and reactivation targets have been identified, along with opportunities to reduce operating costs through operational synergies with existing properties. Combined with the acquired lands, the property exited 2004 with production of approximately 1,230 bbl/d of operated light oil and 415 mcf/d of natural gas, for total interest production of approximately 1,300 boe/d.

In 2005, the Trust plans to recomplete up to five low rate or suspended wells, conserve acquired solution gas production and review the oil blending facilities on the acquired lands for possible expansion. In addition to optimizing the existing Cummings "A" waterflood, the Sparky formation will be reviewed for waterflood implementation..

JOHN LAKE

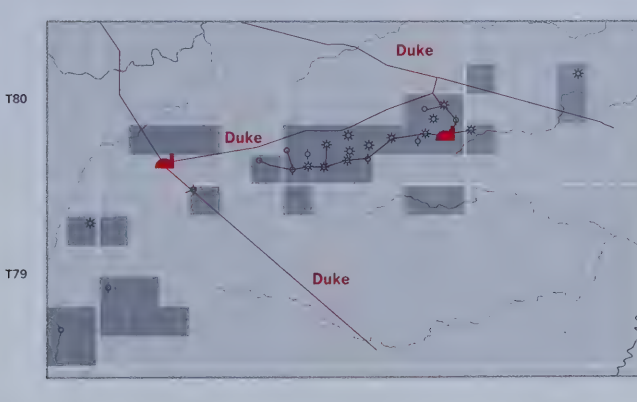
The Trust holds an average 60 percent, operated working interest in the John Lake area. The property is characterized by multi-zone production from the Labiche, Colony, Viking, Grand Rapids, McLaren and Waseca formations. The property produced approximately 7,760 mcf/d of interest natural gas during December 2004. Ongoing optimization of field compression and gathering systems continues to offset field declines and optimize ultimate recoveries. During 2004, the Trust tied-in two wells drilled in 2003, recompleted three wells and conducted five field optimization activities. In 2005, the Trust plans to conduct three recompletions and continue to move portable field compressors throughout the property to offset production decline rates as well as review the property for shallow gas drilling potential.

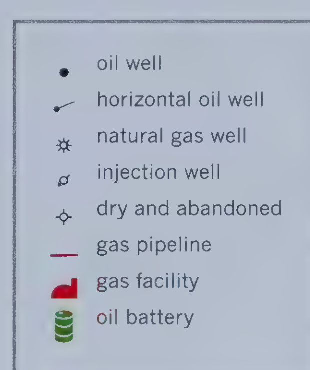


Northeast British Columbia and West Peace River Arch, Alberta

DOE

Doe was acquired as part of the acquisition of Capio Petroleum Corporation in early 2004. Consistent with the Trust's strategy, the property provides Crescent Point with a large gas in place reservoir to exploit, and an operated asset with low operating costs and a large drilling inventory. Located in northeastern British Columbia adjacent to the Alberta border, the property is currently developed by 20 sweet gas wells, two wells which were tied-in in early 2005 and one well to be tied-in after spring break-up in 2005. Production in 2004 from the Doe property averaged 5,000 mcf/d. Gas is gathered to the Trust's operated compressor facility and produced directly into the adjacent Duke/Westcoast sales line resulting in low operating costs, reduced royalty rates and high netbacks. In 2004, the Trust drilled 10 (9.0 net) wells, achieving a success rate of 80 percent, optimized field compression and commenced field wide pressure surveys to determine future drilling locations and ultimate field recoveries. In 2005, the Trust plans to drill up to four wells and continue to optimize field compression and power costs.





Drilling Results

Crescent Point drilled a total of 38 (31.8 net) wells in 2004, achieving an overall success rate of 95 percent. Due to the increase in oil prices in 2004, the majority of capital was directed towards oil production targets.

The following table summarizes the Trust's 2004 drilling results:

	Gas	Oil	D&A	Service	Standing	Total	Net	% Success
Southeast Saskatchewan	-	24	-	3	-	27	21.8	100
South/Central Alberta	1	-		-	-	1	1.0	100
Northeast BC and West Peace River Arch, Alberta	8	-	-	-	2	10	9.0	80
Total	9	24	-	3	2	38	31.8	95

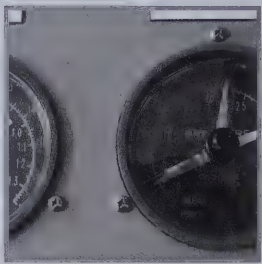
2005 Drilling Program Update

The Trust plans to drill up to 14 gross (11.8 net) wells, two gross (1.4 net) water injection wells and to recomplete up to four gross (4.0 net) wells in the first quarter of 2005. To date, two gross (1.4 net) wells have been drilled at Innes, five gross (4.9 net) wells have been drilled at the Manor area, and one gross (0.7 net) horizontal well and two injection (1.4 net) wells have been drilled at the Tatagwa Unit, achieving an overall success rate of 100 percent and adding approximately 525 boe/d of initial interest production. Construction of a pipeline from the two new pool discoveries at Auburnton to the Queensdale facility has commenced and will be completed by the end of March. Current production levels exceed first quarter budget targets.

National Instrument 51-101

Crescent Point's year end reserve report is compliant with National Instrument 51-101 ("NI 51 – 101").

BACKGROUND



On July 18, 2003, the Alberta Securities Commission (ASC) issued a Notice with respect to the previous National Policy Statement No. 2-B Guide for Engineers and Geologists Submitting Oil and Gas Reports to Canadian Provincial Securities Administrators ("NP 2-B") used to evaluate and annually report a company's reserves. The ASC stated that the Canadian Securities Administrators (CSA) "no longer consider the reserves definitions and the specific disclosure requirements set out in NP 2-B to be sufficiently clear or comprehensive to meet the needs of market participants." As such, NI 51-101 was developed to "enhance investor confidence in Canadian capital markets and facilitate the raising of new capital by oil and gas reporting issuers ... The Instrument establishes disclosure standards and procedures somewhat akin to those long applied to financial disclosure."

Implementation of NI 51-101 became standard for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. NI 51-101 establishes a program of continuous disclosure and includes specific reporting requirements. The Standing Committee on Reserves Evaluation of the Calgary Chapter of the Society of Petroleum Evaluation Engineers ("SPEE") and the Standing Committee on Reserves Definitions of the Canadian Institute of Mining, Metallurgy and Petroleum Society ("CIM") developed the Canadian Oil and Gas Evaluation Handbook ("COGEH") to serve as the guideline for conducting and reporting reserve evaluations. Canadian securities regulators require reporting issuers to comply with COGEH. Volume 1 of the handbook entitled "Reserve Definitions and Evaluation Practices and Procedures" was published in June 2002. Continuing clarification of the guidelines is expected as companies make the transition to the new reporting requirements.

COGEH RESERVE DEFINITIONS

Proved Reserves

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. There is at least a 90 percent probability that recovered reserves will equal or exceed the assigned proved reserves.

Probable Reserves

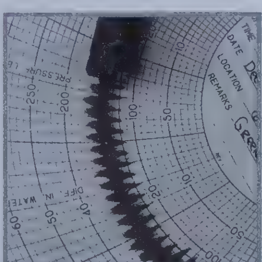
Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. There is at least a 50 percent probability that the quantities recovered will equal or exceed the sum of the assigned proved plus probable reserves. As such, under the definitions of NI 51-101, the proved plus probable reserves represent the "best estimate" of recoverable reserves.

Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

EFFECT ON CRESCENT POINT RESERVES ASSIGNMENT

In consultation with Crescent Point's independent engineers, proved reserves assigned under NI 51-101 are generally expected to be equal to or slightly less than those that would have been assigned under NP-2B, while proved plus probable reserves assigned under NI 51-101 would be comparable to the proved plus 50 percent risked probable or "established" reserves under NP-2B. For comparison to previous reports prepared under NP-2B, proved reserves are compared on an equivalent basis while the new proved plus probable reserves are compared to the previous "established" reserves.



OTHER EFFECTS

- Finding, development and acquisition costs are reported on a proved and proved plus probable reserves basis only.
- Reserves expected to be produced beyond 50 years from the effective date are excluded from reporting.
- Drills previously classified as probable may not be included under the new definition of probable depending on their previously assigned risk level.
- The majority of drills forecast must be forecasted over the next two years.

Reserves and Finding, Development and Acquisition Costs

All reserves quoted are defined under NI 51-101 guidelines. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate".

Crescent Point entered 2004 with total reserves of 18.4 mmboe proved and 24.1 mmboe proved plus probable as independently evaluated by GLJ. As a result of the Trust's activities in 2004, Crescent Point added 7.3 mmboe proved and 10.2 mmboe proved plus probable reserves, net of 3.5 mmboe of production. The Trust exited 2004 with 25.7 mmboe proved and 34.3 mmboe proved plus probable reserves and reserve life indices of 6.8 years proved and 9.1 years proved plus probable, based on the Trust's 2005 production forecast of 10,350 boe/d.

During 2004, oil and gas capital expenditures net of dispositions (including the purchase price of corporate acquisitions) were $192.6 million. Based on reserve additions of 10.8 mmboe proved and 13.8 mmboe proved plus probable, the Trust had finding, development and acquisition costs, excluding future development costs, for 2004 of $17.76 per proved boe and $13.99 per proved plus probable boe. The Trust's rolling four-year average for finding, development and acquisition costs (excluding future development costs) for proved plus probable reserves was $9.38 per boe. Crescent Point's finding, development and acquisition costs for 2004, including future development costs of $5.8 million for proved and $5.5 million for proved plus probable reserves, were $18.29 per proved boe and $14.39 per proved plus probable boe.

SUMMARY OF RESERVES AND ECONOMICS

As at December 31, 2004 (1)

	RESERVES (2)								BEFORE TAX PRESENT VALUE - ($000)			
	Oil (mbbl)		Gas (mmcf)		NGLs (mbbl)		Total (mboe)		Discount Rate			
Description	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Undiscounted	10%	12%	15%
Proved producing	18,194	15,782	16,177	13,089	159	132	21,049	18,096	361,975	237,777	225,253	209,535
Proved non-producing	3,528	3,034	6,689	5,482	44	34	4,688	3,982	75,982	46,543	42,862	38,135
Total proved	21,722	18,816	22,866	18,571	203	166	25,737	22,078	437,957	284,320	268,115	247,670
Probable	6,898	6,002	9,646	7,761	65	51	8,570	7,346	163,258	77,827	70,174	61,058
Total proved plus probable	28,620	24,818	32,512	26,332	268	217	34,307	29,424	601,215	362,147	338,289	308,728

(1) Based on GLJ's January 1, 2005 escalated price forecast.

(2) "Gross reserves" are the total Trust's working interest share before deduction of any royalties. "Net reserves" are the total Trust's working interest share after deducting royalties.

RESERVE RECONCILIATION

Gross Reserves (1)

For the year ended December 31, 2004

	CRUDE OIL AND NGLs (mbbl)			NATURAL GAS (mmcf)			TOTAL (mboe)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Opening Balance January 1, 2004	15,732	4,857	20,589	16,067	4,719	20,786	18,409	5,644	24,053
Acquired	5,917	2,047	7,964	14,192	5,259	19,451	8,282	2,923	11,205
Disposed	-	-	-	-	-	-	-	-	-
Production	(2,494)	-	(2,494)	(6,124)	-	(6,124)	(3,515)	-	(3,515)
Development	1,680	246	1,926	237	(22)	215	1,721	240	1,961
Technical Revisions	1,090	(187)	903	(1,506)	(310)	(1,816)	840	(237)	603
Closing Balance December 31, 2004	21,925	6,963	28,888	22,866	9,646	32,512	25,737	8,570	34,307

(1) Based on GLJ's January 1, 2005 escalated price forecast. "Gross reserves" are the Trust's working interest share before deduction of any royalties.

FINDING, DEVELOPMENT AND ACQUISITION COSTS (excluding future development costs)

For the year ended December 31, 2004

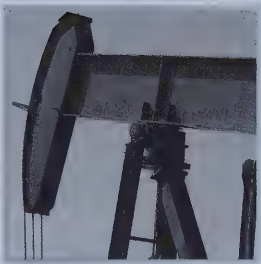
	CAPITAL EXPENDITURES (1)(3)		RESERVES (2)				FINDING, DEVELOPMENT AND ACQUISITION COSTS (1)	
			Proved		Proved Plus Probable		Proved	Proved Plus Probable
	$000	%	mboe	%	mboe	%	$/Boe	$/Boe
Development and technical revisions	26,653	14	2,561	24	2,564	19	10.41	10.40
Acquisitions, net of dispositions	165,918	86	8,282	76	11,205	81	20.03	14.81
Total	192,571	100	10,843	100	13,769	100	17.76	13.99

(1) Development and technical revisions exclude the change during the most recent financial year in estimated future development costs relating to proved and proved plus probable reserves. These costs would add $5.8 million and $5.5 million, respectively, to the proved and proved plus probable reserves categories. Including these changes, the proved and proved plus probable finding, development and acquisition costs are $18.29 and $14.39 per boe, respectively.

(2) Gross Trust interest reserves are used in this calculation (working interest reserves, before deduction of any royalties).

(3) The capital expenditures includes the purchase price of corporate acquisitions rather than the amount allocated to property, plant and equipment for accounting purposes.

2005 Acquisition and Development Outlook



Crescent Point will continue to add value through careful technical and economic assessment of acquisition opportunities. The Trust is well positioned to continue pursuing its acquisition strategy with its strong financial position and industry network with players in its core areas as demonstrated by the eight strategic acquisitions in 2004.

The Trust will also continue to develop and exploit its existing core properties, while aiming to expand in these areas through acquisitions and/or land purchases where appropriate. The Trust is expected to invest approximately $26 million in drilling, optimization, land and seismic activities. The development drilling plans include up to 34 gross (29.0 net) wells, up to five gross (4.1 net) water injection wells and up to nine gross (9.0 net) recompletions. With a current inventory of more than 130 low risk development locations and 5,500 boe/d of risked production additions in its core areas, Crescent Point is well positioned to maintain its current production levels, which will provide for stable and sustainable production and distributions through 2005 and beyond.

Land Holdings

As at December 31, 2004, Crescent Point had an undeveloped land base of 80,000 net acres with an average working interest of approximately 65 percent.

When reviewing undeveloped land holdings, the goal of the Trust is to establish reserves, production and cash flow from idle or non-performing assets with no risked capital. The Trust's skilled technical team achieves this by performing a detailed geologic and engineering evaluation to identify those lands which do not meet the criteria for development within the Trust's main focus areas. The Trust then solicits and negotiates farmout and joint venture/sponsorship arrangements with aggressive, technically strong management teams willing to spend growth capital on higher risk, non-core land holdings.

During 2004, Crescent Point entered into three farmout/option agreements which have resulted in drilling three wells, with an additional well to be drilled in 2005. These properties and related expenditures did not meet Crescent Point's investment criteria. Further, these wells will be drilled at no cost to Crescent Point and the Trust will generally receive a convertible gross overriding royalty until payout at which time such royalty will convert to a working interest of approximately 50 percent of Crescent Point's pre-farmout working interest.

The Trust's undeveloped land holdings are summarized below:

Acreage Summary	2004	2003
Net (acres)	80,000	51,000

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated March 11, 2005 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2004 for a full understanding of the financial position and results of operations of Crescent Point Energy Trust ("Crescent Point" or the "Trust"). All amounts are expressed in Canadian dollars. A barrel of oil equivalent ("boe") is based on a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Throughout this discussion and analysis, Crescent Point uses the terms cash flow from operations, cash flow per unit, cash flow per unit - diluted, market value and payout. These terms do not have any standardized meaning as prescribed by Canadian generally accepted accounting principles and therefore they may not be comparable with the calculation of similar measures presented by other issuers. These measures have been described and presented in order to provide unitholders and potential investors with additional information regarding the Trust's liquidity and its ability to generate funds to finance its operations. Management utilizes cash flow from operations as a key measure to assess the ability of the Trust to finance operating activities and capital expenditures. All references to cash flow from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital.

Forward Looking Information

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control, including the impact of general economic conditions; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition, and the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition, there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. Therefore Crescent Point's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits Crescent Point will derive therefrom.

All tabular amounts are in thousands, except per unit and volume amounts. Certain financial information of the year ended December 31, 2003 has been restated for changes in accounting policies and to conform with the current year presentation.

Plan of Arrangement

During 2003, Crescent Point Energy Ltd. ("Crescent Point Energy" or the "Corporation") completed a strategic merger whereby it acquired Tappit Resources Ltd. ("Tappit") and converted into an oil and gas income trust through a Plan of Arrangement (the "Plan"). In addition, the shareholders of Crescent Point Energy and Tappit received shares in StarPoint Energy Ltd. ("StarPoint"), a separate, publicly listed, exploration and production company. The special meeting of the shareholders approving the Plan was held on August 21, 2003. The effective date for the transaction was September 5, 2003.

The Plan involving conversion to the Trust has been accounted for as a continuity of interests. Accordingly, the consolidated financial statements for the year ended December 31, 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Crescent Point Energy. The comparative information for the year ended December 31, 2003 reflects the results of operations and cash flows of Crescent Point Energy and its subsidiaries up to September 5, 2003, and the results of the Trust and its subsidiaries from September 5 to December 31, 2003.

The term "units" has been used to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

Results of Operations

Production

Average daily production increased by 70 percent to 9,604 boe/d in 2004 compared to 5,659 boe/d in 2003. This increase is comprised of a 50 percent increase in average crude oil and natural gas liquids ("NGLs") production to 6,815 bbl/d in 2004 from 4,536 bbl/d in 2003, and a 148 percent increase in average natural gas production to 16,733 mcf/d in 2004 from 6,738 mcf/d in 2003. The overall increase in production is attributable to the Plan of Arrangement completed with Tappit on September 5, 2003, the acquisition of Capio Petroleum Corporation ("Capio") on January 6, 2004, four property acquisitions that closed in the third and fourth quarters of 2004, other minor acquisitions in 2004 and the optimization of existing properties.

Daily Production Volumes	2004	2003	% Change
Crude oil and NGLs (bbl/d)	6,815	4,536	50
Natural gas (mcf/d)	16,733	6,738	148
Total (boe/d)	9,604	5,659	70
Crude oil and NGLs	71%	80%	(9)
Natural gas	29%	20%	9
Total	100%	100%	-

Marketing and Prices

Crescent Point's average realized crude oil and NGL price increased by 25 percent in 2004 to $46.40 per bbl from $37.05 per bbl in 2003. The increase is mainly attributable to the overall increase in commodity prices in the second half of 2004. For comparison, benchmark Edmonton light sweet oil increased by 22 percent in 2004.

The average realized natural gas price increased three percent in 2004 to $6.46 per mcf from $6.28 per mcf in 2003. In comparison, the AECO monthly index decreased two percent to $6.54 per mcf in 2004 from $6.67 per mcf in 2003.

Average Realized Prices (1)	2004	2003	% Change
Crude oil and NGLs ($/bbl)	46.40	37.05	25
Natural gas ($/mcf)	6.46	6.28	3
Total ($/boe)	44.18	37.18	19

1) The average realized prices reported are before realized financial instrument losses and transportation charges.

Benchmark Pricing	2004	2003	% Change
Edmonton light sweet oil (Cdn$/bbl)	52.91	43.23	22
WTI crude oil (US$/bbl)	41.42	31.14	33
AECO natural gas (Cdn$/mcf)	6.54	6.67	(2)
Exchange rate – Cdn$/US$	0.77	0.72	7

Financial Instruments and Risk Management

Management of cash flow variability is an integral component of Crescent Point's business strategy. Changing business conditions are monitored regularly and reviewed with the Board of Directors to establish hedging guidelines used by management in carrying out the Trust's strategic hedging program. The risk exposure inherent in movements in the price of crude oil and natural gas, fluctuations in the Cdn/U.S. dollar exchange rate and interest rate movements on long term debt are all proactively managed by Crescent Point through the use of forward sale financial transactions with reputable, financially sound counterparties. The Trust considers these contracts to be an effective means to manage cash flow.

All of the Trust's financial instruments are in Canadian dollars and referenced to WTI and AECO, unless otherwise noted. These financial instruments allow the Trust to hedge both commodity prices and fluctuations in the Cdn/U.S. dollar exchange rate.

The realized losses on financial instruments in 2004 increased to $18,855,000, or $5.36 per boe, from $2,722,000, or $1.32 per boe, in 2003. This increase is attributable to the increase in market commodity prices, and an increase in the production volumes hedged.

The following is a summary of the realized financial instrument losses:

Risk Management ($000 except per boe and volume amounts)	2004	2003	% Change
Average crude oil volumes hedged (bbl/d)	3,019	1,900	59
Crude oil realized financial instrument loss	(18,507)	(2,458)	(653)
per bbl	(7.42)	(1.48)	(401)
Average natural gas volumes hedged (GJ/d)	2,638	1,336	97
Natural gas realized financial instrument loss	(348)	(264)	(32)
per mcf	(0.06)	(0.11)	45
Average barrels of oil equivalent hedged (boe/d)	3,436	2,111	63
Total realized financial instrument loss	(18,855)	(2,722)	(593)
per boe	(5.36)	(1.32)	(306)

The Trust has not designated any of its risk management activities as accounting hedges under the Canadian Institute of Chartered Accountants (the "CICA") accounting guideline AcG-13 and, accordingly, has marked-to-market its financial instruments. This resulted in an unrealized financial instrument loss of $7,987,000 for the year ended December 31, 2004. The loss was incurred as a result of higher forward oil prices at December 31, 2004 as compared to the Trust's fixed prices contracts.

Crescent Point currently has the following fixed price oil contracts, costless collar oil contracts and interest rate swaps in place:

Fixed Price Oil Contracts	Weighted average volume (bbl/d)	Weighted average price ($Cdn/bbl)	Index
January 1, 2005 to December 31, 2005	3,701	44.18	WTI
January 1, 2006 to December 31, 2006	3,000	51.89	WTI
January 1, 2007 to March 31, 2007	500	56.54	WTI

Costless Collar Oil Contracts	Weighted average volume (bbl/d)	Floor ($Cdn/bbl)	Ceiling ($Cdn/bbl)	Index
July 1, 2005 to December 31, 2005	250	50.00	57.00	WTI
August 1, 2005 to December 31, 2005	250	50.00	60.00	WTI
January 1, 2006 to December 31, 2006	250	52.00	61.65	WTI
January 1, 2006 to December 31, 2006	250	53.00	66.50	WTI

Interest Rate Swaps	Amount ($000)	Interest rate (%)
January 1, 2005 to February 15, 2005	8,000	4.20
January 1, 2005 to March 4, 2005	12,000	4.03

Revenue

Revenue increased 102 percent to $155,299,000 in 2004 from $76,792,000 in 2003. This increase in revenue consists of an 89 percent increase in crude oil and NGL revenue and a 156 percent increase in natural gas revenue. Revenue increased by 102 percent due to a combination of increased crude oil and natural gas production from the Trust's increased asset base and higher overall commodity prices.

Revenue (1) ($000)	2004	2003	% Change
Crude oil and NGL sales	115,732	61,350	89
Natural gas sales	39,567	15,442	156
Gross revenue	155,299	76,792	102

1) Revenue is reported before transportation charges.

Transportation Expenses

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles" ("GAAP"), which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Trust recorded revenue gross of transportation charges and a transportation expense on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow.

The transportation expenses in 2004 were $3,968,000 or $1.13 per boe, as compared with transportation expenses of $2,074,000 or $1.00 per boe in 2003. The transportation expense per boe increased due to higher transportation tariffs on the properties acquired in 2004 as compared to the prior year.

Transportation Expenses ($000 except per boe amounts)	2004	2003	% Change
Transportation expenses	3,968	2,074	91
Per boe	1.13	1.00	13

Royalty Expenses

Royalties, net of Alberta Royalty Tax Credit ("ARTC") increased to $28,675,000 in 2004 from $14,044,000 in 2003, representing a 104 percent increase. The increase is consistent with the 102 percent increase in gross revenue which resulted from increased production and higher commodity prices. Royalties as a percentage of oil and gas sales remained stable at 18 percent.

Royalties ($000 except per boe amounts)	2004	2003	% Change
Total royalties, net of ARTC	28,675	14,044	104
As a % of oil and gas sales	18%	18%	-
Per boe	8.16	6.80	20

Operating Expenses

Operating expenses increased 17 percent to $6.53 per boe in 2004, from $5.60 per boe in 2003. This increase is due to the higher operating costs associated with the three properties acquired in the third quarter of 2004, along with general increases in the industry, offset by optimizations realized on existing properties.

Operating Expenses ($000 except per boe amounts)	2004	2003	% Change
Operating expenses	22,941	11,561	98
Per boe	6.53	5.60	17

Netbacks

Note: The following discussion of netbacks refers to netbacks after realized financial instrument losses.

In 2004, Crescent Point received an average crude oil and NGL netback of $22.56 per bbl as compared to $22.95 per bbl in 2003, and a natural gas netback of $4.02 per mcf as compared to $3.41 per mcf in 2003. On a total commodity basis, the Trust received a netback of $23.00 per boe in 2004, as compared to $22.46 per boe in 2003. The Trust's overall netback increased by $0.54 per boe or two percent primarily due to higher average realized commodity prices in 2004 as compared to 2003.

Netbacks	2004	2003	% Change
Crude oil and NGLs ($/bbl)			
Production (bbl/d)	6,815	4,536	50
Price	46.40	37.05	25
Transportation expenses	(1.09)	(1.01)	8
Financial instruments – realized loss	(7.42)	(1.48)	(401)
Royalty expenses, net	(8.23)	(6.41)	28
Operating expenses	(7.10)	(5.20)	37
Netback	22.56	22.95	(2)
Natural gas ($/mcf)			
Production (mcf/d)	16,733	6,738	148
Price	6.46	6.28	3
Transportation expenses	(0.20)	(0.17)	18
Financial instruments – realized loss	(0.06)	(0.11)	45
Royalty expenses, net	(1.33)	(1.39)	(4)
Operating expenses	(0.85)	(1.20)	(29)
Netback	4.02	3.41	18
Total ($/boe)			
Production (boe/d)	9,604	5,659	70
Price	44.18	37.18	19
Transportation expenses	(1.13)	(1.00)	13
Financial instruments – realized loss	(5.36)	(1.32)	(306)
Royalty expenses, net	(8.16)	(6.80)	20
Operating expenses	(6.53)	(5.60)	17
Netback	23.00	22.46	2

General and Administrative Expenses

General and administrative costs incurred by the Trust in 2004 were $5,775,000. Of this, $1,048,000 was capitalized as part of the Trust's drilling and development program, resulting in net administrative expenses of $4,727,000 or $1.34 per boe. This compares with general and administrative costs in 2003 of $3,612,000 of which $1,472,000 was capitalized, resulting in net administrative expenses of $2,140,000 or $1.04 per boe. The 29 percent increase in general and administrative expenses on a per boe basis relates to higher compensation costs in the year based on the successful results achieved by the Trust in 2004.

General and Administrative Expenses ($000, except per boe and volume amounts)	2004	2003	% Change
General and administrative costs	5,775	3,612	60
Capitalized	(1,048)	(1,472)	(29)
General and Administrative Expense	4,727	2,140	121
Per boe	1.34	1.04	29

Interest Expense

Interest expense for the year ended December 31, 2004 amounted to $3,398,000 compared with $1,640,000 in 2003. The increase in interest expense in 2004 is due to the growth of the Trust's overall asset base and corresponding capital structure, which resulted in higher average debt levels in the year.

Interest Expense ($000, except per boe amounts)	2004	2003	% Change
Interest Expense	3,398	1,640	107
Per boe	0.97	0.79	23

Depletion, Depreciation and Amortization ("DD&A")

Crescent Point's depletion, depreciation and amortization for the year ended December 31, 2004 was $40,157,000 or $11.42 per boe, as compared to depletion of $19,187,000 or $9.29 per boe in 2003. The higher DD&A rate is due to the acquisitions completed in 2004 which carried a higher cost per barrel of reserves as compared to the Trust's existing properties, a trend observed throughout the Canadian oil and gas industry.

Depletion, Depreciation and Amortization ($000 except per boe amounts)	2004	2003	% Change
Depletion, Depreciation and Amortization	40,157	19,187	109
Per boe	11.42	9.29	23

Taxes

Capital and other taxes paid or payable were $2,854,000 in 2004 as compared with $770,000 in 2003. The increase in capital taxes is due to higher levels of debt and equity, resulting mainly from the acquisitions completed in 2004.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. In the Trust structure, payments are made between the operating companies and the Trust, transferring both the income and tax liability to the unitholders. It is therefore expected the Trust will not incur any cash income taxes in the future, and as such the future tax liability recorded on the balance sheet will be recovered through future earnings.

In the first quarter of 2004, the Alberta government passed legislation to reduce provincial corporate income tax rates to 11.5 percent from 12.5 percent, effective April 1, 2004. Crescent Point's expected future income tax rate incorporating this rate reduction is approximately 35 percent as compared to 36 percent in 2003.

The future income tax recovery for 2004 was ($12,014,000), as compared to the future income tax expense for 2003 of $8,101,000. The increase in the future income tax recovery is primarily attributable to the increase in the net income of the mutual fund trust.

Taxes ($000)	2004	2003	% Change
Capital and other tax expense	2,854	770	271
Future income expense (recovery)	(12,014)	8,101	(248)

Cash Flow and Net Income

Note - all per unit amounts discussed in this section of the MD&A represent per unit-diluted amounts.

Crescent Point generated cash flow from operations for 2004 of $69,828,000 or $2.49 per unit as compared to $36,626,000 or $1.99 per unit in 2003. Normalizing cash flow in 2003 by excluding $5,215,000 of non-recurring expenses relating to the corporate reorganization results in cash flow of $41,841,000 or $2.27 per unit. The $0.22 per unit increase in the normalized cash flow in 2004 relates to the accretive acquisitions completed in the year, increased production on existing properties and higher corporate netbacks.

Crescent Point's net income for 2004 was $30,659,000 or $1.09 per unit as compared to $9,134,000 or $0.50 per unit in 2003. The increase in net income also relates to a combination of the overall growth in the Trust's asset base resulting in increased production and to higher corporate netbacks.

Cash Flow and Net Income ($000, except per unit amounts)	2004	2003	% Change
Cash flow from operations	69,828	36,626	91
Cash flow from operations per unit-diluted	2.49	1.99	25
Net income	30,659	9,134	236
Net income per unit-diluted	1.09	0.50	118

Cash Distributions

Crescent Point's distributions to unitholders are paid monthly and are dependent upon commodity prices, production levels and the amount of capital expenditures to be funded from cash flow. The Trust contributes part of its cash flow towards the capital program to provide for more sustainable distributions in the future. The actual amount of the distributions are at the discretion of the Board of Directors. In the event that commodity prices are higher than anticipated and a cash surplus develops during a quarter, the surplus may be used to increase distributions, reduce debt, and/or increase the capital program.

Cash distributions of $2.04 per Trust unit were declared in 2004. Of this amount, $1.87 per unit was paid in 2004, and $0.17 per unit was paid on January 17, 2005. Cash flow from operations for the period ending

December 31, 2004 was $2.49 per unit representing a payout ratio of 82 percent on a per unit-diluted basis (including the exchangeable shares and restricted units). The payout ratio of 82 percent per unit-diluted in 2004 represents a two percent reduction from the September 5, 2003 to December 31, 2003 payout ratio of 84 percent. The payout ratio excluding exchangeable shares and restricted units (which do not receive cash distributions) was 77 percent for 2004, as compared to 75 percent for the period September 5, 2003 to December 31, 2003.

The Trust has maintained monthly distributions of $0.17 per unit since its inception on September 5, 2003, providing total accumulated distributions to unitholders of $2.72 per unit.

Taxation of Cash Distributions

Cash distributions are comprised of a return on capital portion (taxable) and a return of capital portion (tax deferred). For cash distributions received by a Canadian resident, outside of a registered pension or retirement plan in the 2004 taxation year, the breakdown is 71.8 percent taxable with the remaining 28.2 percent being tax deferred.

For 2005, Crescent Point estimates that 75 percent of cash distributions will be taxable, and 25 percent will be a return of capital. Actual taxable amounts will be dependent on, among other things, actual distributions paid, commodity prices realized throughout the year and additions to the tax pools resulting from capital spending.

The following is a breakdown of the cash distributions per unit paid or payable by the Trust with respect to the record dates from January 31, 2004 to December 31, 2004 for Canadian tax purposes:

Record Date	Payment Date	Taxable Amount (Box 26 Other Income)	Tax Deferred Amount (Box 42 Return of Capital)	Total Cash Distribution
January 31, 2004	February 16, 2004	$0.12206	$0.04794	$0.17
February 29, 2004	March 15, 2004	$0.12206	$0.04794	$0.17
March 31, 2004	April 15, 2004	$0.12206	$0.04794	$0.17
April 30, 2004	May 17, 2004	$0.12206	$0.04794	$0.17
May 31, 2004	June 15, 2004	$0.12206	$0.04794	$0.17
June 30, 2004	July 15, 2004	$0.12206	$0.04794	$0.17
July 31, 2004	August 16, 2004	$0.12206	$0.04794	$0.17
August 31, 2004	September 15, 2004	$0.12206	$0.04794	$0.17
September 30, 2004	October 15, 2004	$0.12206	$0.04794	$0.17
October 31, 2004	November 15, 2004	$0.12206	$0.04794	$0.17
November 30, 2004	December 15, 2004	$0.12206	$0.04794	$0.17
December 31, 2004	January 17, 2005	$0.12206	$0.04794	$0.17
Total Per Unit		$1.46472	$0.57528	$2.04

Capital Expenditures

In 2004, capital expenditures (net of dispositions) totaled $174,335,000 as compared to $124,464,000 in 2003. The capital expenditures are summarized as follows:

Capital Expenditures (net) (1) ($000)	2004	2003	% Change
Property acquisitions (2)	145,152	99,675	46
Drilling and development	26,868	22,488	19
Capitalized administration	1,048	1,472	(29)
Other	1,267	829	53
Total	174,335	124,464	40

1) The capital expenditures do not include the amounts recorded to property, plant and equipment in respect of asset retirement obligations.
2) The property acquisitions for the year ended December 31, 2003 are net of the transfer of exploration assets with a net book value of $10,055,000 to StarPoint.

The Trust closed eight acquisitions in 2004. These include the acquisition of Capio for approximately $82,707,000 ($61,688,000 was allocated to property, plant and equipment), three property acquisitions in the Trust's main operating area of southeast Saskatchewan for $64,742,000, a property acquisition at

Sounding Lake for $14,189,000 and a property acquisition at Killam for $3,528,000. There were other minor acquisitions and dispositions in 2004 totaling $1,005,000.

The Trust's 2005 capital program, excluding acquisitions, is budgeted to be approximately $26,000,000. The program is expected to be financed by residual cash flow after distribution payments and the distribution reinvestment programs.

The Trust does not set a budget for acquisitions. The Trust searches for opportunities that align with strategic parameters and evaluates each prospect on a case-by-case basis. The Trust's acquisitions are expected to be financed through bank debt, the distribution reinvestment programs and new equity issuances.

Goodwill

The Trust's goodwill is comprised of $21,171,000 which arose on the 2003 acquisition of Tappit and $36,976,000 which arose on the 2004 acquisition of Capio. The Trust performed a goodwill test as at December 31, 2004 and no impairment of goodwill exists.

Asset Retirement Obligation

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The asset retirement obligation increased by $16,208,000 during 2004 for three main reasons. There were liabilities of $9,482,000 recorded in respect of the acquisitions and wells drilled during the year. Secondly, there were additional liabilities of $6,242,000 recorded due to changes in estimates of prior periods. The Trust bases its asset retirement obligation cost estimates on information published by the Alberta Energy Utilities Board ("AEUB") for their liability ratings. During the year, the AEUB published a new directive outlining estimates for abandonment and reclamation costs. Crescent Point increased its asset retirement cost estimates to ensure consistency with the estimates published by the AEUB. Lastly, there was accretion expense of $798,000 recorded in 2004, which was partially offset by actual retirement expenditures of $314,000.

Reclamation Fund

During the third quarter of 2004, the Trust implemented a reclamation fund to provide for future asset retirement costs. Effective July 1, 2004, the Trust began contributing $0.15 per barrel of production to the reclamation fund which results in minimum annual contributions of approximately $550,000 based upon properties owned at December 31, 2004. Additional contributions are made at the discretion of the Board of Directors. Contributions to the fund during 2004 were $539,000, of which $314,000 was used in asset retirement activities during the year.

Liquidity and Capital Resources

In the fourth quarter of 2004, the Trust's credit facility was increased from $105,000,000 to $135,000,000 and syndicated with two additional Canadian chartered banks. As at December 31, 2004, the Trust had net debt of $95,360,000 compared with $38,417,000 as at December 31, 2003. The amount drawn under the credit facility by the Trust at December 31, 2004 was $92,720,000, providing in excess of $42,000,000 of unutilized credit capacity. Given the significant amount available but unutilized under the credit facility at December 31, 2004 and the success raising new equity during the year (see Unitholders' Equity discussion below), the Trust believes it has sufficient capital resources to meet its obligations and achieve excellent financial results going forward.

At the end of 2004, Crescent Point was capitalized with 15 percent debt and 85 percent equity, as compared with 12 percent debt and 88 percent equity at the end of 2003 (based on year-end market capitalization). The Trust's net debt to cash flow ratio was 1.4 times at the end of 2004 (using the annual cash flows for 2004), as compared with 1.0 times at the end of 2003. Crescent Point's net debt to cash flow ratio increased in 2004 due to funding the Sounding Lake property acquisition of $14,189,000 in the fourth quarter of 2004 through the existing credit line. The Trust's projected annual cash flow and debt will result in a net debt to cash flow ratio below 1.0 times in 2005.

Capitalization Table ($000 except unit and per unit amounts)	**2004**	**2003**
Bank debt	92,720	40,220
Less: working capital (deficiency) [1]	2,640	(1,803)
Net debt [1]	95,360	38,417
Units outstanding and issuable for exchangeable shares	30,906,277	21,265,233
Market price at end of year (per unit)	16.85	13.39
Market capitalization	520,771	284,741
Total capitalization [2]	616,131	323,158
Net debt as a percentage of total capitalization	15%	12%
Cash flow	69,828	36,626
Net debt to cash flow	1.4	1.0

1) The working capital (deficiency) and net debt exclude the risk management liability.
2) Total capitalization as presented does not have any standardized meaning prescribed by GAAP and, therefore, it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

Unitholders' Equity

Crescent Point's total capitalization increased 91 percent to $616,131,000 at December 31, 2004, with the market value of Trust units representing 85 percent of total capitalization. This compares with the total capitalization of $323,158,000 at December 31, 2003, with the market value of Trust units representing 88 percent of total capitalization.

On January 6, 2004, the Trust closed a bought deal equity financing of 5,150,000 units for gross proceeds of $65,662,500 ($12.75 per Trust unit). The proceeds from this financing were used to fund the acquisition of Capio.

On September 9, 2004, the Trust closed a bought deal equity financing pursuant to which 3,000,000 units were sold for proceeds of $45,000,000 ($15.00 per Trust unit). The proceeds from this financing were used to fund three separate property acquisitions totaling $64,742,000.

During the year ended December 31, 2004, the units traded in the ranges of $13.00 to $18.25, with an average daily trading volume of 105,000 units.

For the year ended December 31, 2004, the distribution reinvestment and premium distribution reinvestment plans resulted in an additional 1,208,002 units being issued at an average price of $14.62, raising a total of $17,657,000. Participation levels in these plans is currently in excess of 30 percent. The cash raised through these alternative equity programs is used for general corporate purposes. Crescent Point will continue to monitor participation levels and utilize these funds in the most effective manner.

The Trust established the Restricted Unit Bonus Plan on September 5, 2003. Under the terms of the Restricted Unit Bonus Plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 1/3 percent on each of the first, second and third anniversaries of the grant date. Restricted unitholders are eligible for the first third of their monthly distributions for the first year, immediately upon grant. On the date the other two thirds of the restricted units vest, the restricted unitholders are entitled to the accrued distributions from the date of grant.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. The Trust had 400,559 restricted units outstanding at December 31, 2004 compared with 180,200 restricted units outstanding at December 31, 2003. The Trust recorded compensation expense and contributed surplus of $2,294,000 in the year ended December 31, 2004 based on the estimated fair value of the units on the date of grant.

Contractual Obligations and Commitments

The Trust has assumed various contractual obligations and commitments in the normal course of operations. The following table summarizes the Trust's contractual obligations and commitments as at December 31, 2004:

Contractual Obligations - Summary ($000)		Expected Payout Date			
	Total	2005	2006-2007	2008-2009	After 2009
Operating Leases (1)	1,196	470	726	-	-

1) Operating leases includes leases for office space and equipment.

Critical Accounting Estimates

The preparation of the Trust's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Crescent Point can be found in Note 2 to the December 31, 2004 consolidated financial statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of estimates or assumptions.

Depletion, Depreciation and Amortization ("DD&A")

Crescent Point follows the CICA accounting guideline AcG-16 on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of natural gas and crude oil reserves are capitalized and costs associated with production are expensed. The capitalized costs are depleted using the unit-of-production method based on estimated proved reserves using management's best estimate of future prices (see Oil and Gas Reserves discussion below). Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserve estimates (see Asset Impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Asset Retirement Obligation

Upon retirement of its oil and gas assets, the Trust anticipates incurring substantial costs associated with asset retirement activities. Estimates of the associated costs are subject to uncertainty associated with the method, timing and extent of future retirement activities. A liability for these costs and a related asset are recorded using the discounted asset retirement costs and the capitalized costs are depleted on a unit-of-production basis over the associated reserve life. Accordingly, the liability, the related asset and the expense are impacted by changes in the estimates and timing of the expected costs and reserves (see Oil and Gas Reserves discussion below).

Asset Impairment

Producing properties and unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated undiscounted future cash flows to the carrying value of the asset. The cash flows used in the impairment assessment require management to make assumptions and estimates about recoverable reserves (see Oil and Gas Reserves discussion below), future commodity prices and operating costs. Changes in any of the assumptions, such as a downward revision in reserves, a decrease in future commodity prices, or an increase in operating costs could result in an impairment of an asset's carrying value.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired (see Oil and Gas Reserves discussion below), future commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities, and goodwill in the purchase price allocation. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

Goodwill Impairment

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting entity to its carrying value, including goodwill. If the fair value of the reporting entity is

less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the implied value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves (see Oil and Gas Reserves discussion below), future commodity prices, operating costs, production profiles, and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates could result in an impairment of all or a portion of the goodwill carrying value in future periods.

Oil and Gas Reserves
Reserves estimates, although not reported as part of the Trust's financial statements, can have a significant effect on net earnings as a result of their impact on depletion and depreciation rates, asset retirement provisions, asset impairments, purchase price allocations, and goodwill impairment (see discussion of these items above). Independent petroleum reservoir engineering consultants perform evaluations of the Trust's oil and gas reserves on an annual basis. However, the estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, commodity prices, operating and capital costs and production forecasts, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

New Accounting Pronouncements

ACCOUNTING CHANGES IN THE CURRENT YEAR

Full Cost Accounting
Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-16 "Oil and Gas Accounting – Full Cost." The new guideline modifies how the ceiling test is performed, and requires cost centres to be tested for impairment using undiscounted future cash flows which are determined using management's estimate of future prices applied to proved reserves. If the carrying value exceeds the undiscounted cash flows, an impairment loss would be recorded in income. The impairment is measured as the amount by which the carrying amount of property, plant and equipment exceeds the discounted cash flows from proved and probable reserves.

There was no impact on the Trust's carrying amount for property, plant and equipment or to net income as a result of adopting this guideline.

Asset Retirement Obligations
Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." This new section changes the method of accruing for costs associated with the retirement of property, plant and equipment, which an entity is legally obligated to incur. Previously, asset retirement obligations were accrued on an undiscounted unit-of-production basis over the entire life of the asset. The new accounting standard requires that companies record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the reserves. Revisions to the estimated timing of cash flows or the original estimated undiscounted cost would also result in an increase or decrease to the obligation and related asset.

Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The previously reported 2003 amounts have been restated due to the retroactive application of this new standard. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $2,224,000, an increase to property, plant and equipment of $1,902,000, an increase in accumulated earnings of $24,000, a decrease in the site restoration liability of $363,000 and an increase to the future tax liability of $17,000. Net income for the year ended December 31, 2003 increased by $115,000 as a result of the retroactive application of the accounting standard.

There was no impact on the Trust's cash flow or liquidity as a result of adopting this new accounting standard.

Hedging Relationships
Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-13 "Hedging Relationships". Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability, with the change in fair value recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13 and, accordingly, has marked-to-market its financial instruments.

The impact on the Trust's financial statements as at January 1, 2004 was the recognition of a risk management liability and a deferred financial instrument loss (net) of $3,209,000. The deferred financial instrument loss is being recognized in earnings as the contracts expire.

Transportation Expenses

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles," which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Trust has recorded revenue gross of transportation charges and a transportation expense on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow.

FUTURE ACCOUNTING CHANGES

Exchangeable Share Accounting

The CICA issued EIC-151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" in January 2005. The EIC requires that exchangeable shares be presented as either non-controlling interest or debt unless certain criteria are met. The EIC is effective for financial statements issued after July 1, 2005, and is to be applied retroactively with restatement of prior periods. Crescent Point is currently assessing the impact of this EIC on its financial statements and cannot reasonably estimate the impact at this time.

Variable Interest Entities

The CICA issued accounting guideline AcG-15, "Consolidation of Variable Interest Entities" in June 2003. The EIC provides guidance regarding the entities which should be included in consolidated financial statements. The EIC is effective for the Trust's fiscal year beginning January 1, 2005. The Trust has not assessed the impact of this EIC on its financial statements.

Financial Instruments

The CICA issued a new accounting standard, CICA Accounting Standard Handbook section 3855, "Financial Instruments Recognition and Measurement". This standard prescribes how and at what amount financial assets, financial liabilities and non-financial derivatives are to be recognized on the balance sheet. The standard prescribes fair value in some cases while cost-based measures are prescribed in other cases. It also specifies how financial instrument gains and losses are to be presented. The new standard is effective for fiscal years beginning on or after October 1, 2006. The Trust has not assessed the impact of this standard on its financial statements.

Outstanding Trust Unit Data

As at March 3, 2005, the Trust had 29,558,864 Trust units outstanding and 1,217,012 exchangeable shares outstanding. The number of Trust units issuable upon conversion of the exchangeable shares is 1,479,680 Trust units, using the exchange ratio in effect at March 3, 2005.

Selected Annual Information

Annual Financial Results[1] ($000 except per unit amounts)	2004	2003 (restated [2])	2002 (restated [2])
Total revenue [3]	151,331	74,718	24,655
Net income [4]	30,659	9,134	3,341
Net income per unit [4]	1.10	0.50	0.32
Net income per unit-diluted [4]	1.09	0.50	0.30
Cash flow from operations	69,828	36,626	11,893
Cash flow from operations per unit	2.52	1.99	1.12
Cash flow from operations per unit-diluted	2.49	1.99	1.07
Total assets	397,318	208,855	76,572
Total long-term financial liabilities	-	-	-
Cash distributions	53,877	11,697	-
Cash distributions/dividends per unit/share	2.04	0.68	-

1) The financial information has been prepared in accordance with Canadian GAAP, and is measured and reported in Canadian dollars.
2) The comparative annual results have been restated for the retroactive impact of adopting the accounting standard asset retirement obligations.
3) Total revenue reported is net of transportation expenses.
4) Net income and net income before discontinued operations and extraordinary items are the same.

Crescent Point's revenue, net income, cash flow and assets have increased substantially from the year ended December 31, 2002 through the year ended December 31, 2004 due to several corporate and property acquisitions and the Trust's successful drilling and development program.

Summary of Quarterly Results

Quarterly Financial Results ($000 except per unit amounts)	**2004**				**2003 (Restated (3))**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (1)	46,548	39,830	34,130	30,823	22,623	18,671	15,827	17,597
Net income (loss) (2)	24,409	3,058	2,754	438	(626)	1,376	5,125	3,259
Net income (loss) per unit (2)	0.80	0.11	0.10	0.02	(0.03)	0.09	0.37	0.24
Net income (loss) per unit-diluted (2)	0.79	0.11	0.10	0.02	(0.03)	0.09	0.36	0.23
Cash flow from operations	19,875	18,096	16,348	15,509	11,975	6,084	9,368	9,199
Cash flow from operations per unit	0.65	0.65	0.61	0.60	0.63	0.40	0.68	0.67
Cash flow from operations per unit-diluted	0.64	0.64	0.60	0.59	0.62	0.40	0.66	0.64
Capital expenditures	21,728	74,948	8,875	68,784	22,584	66,102	5,676	30,102
Cash distributions	14,834	13,490	12,929	12,624	8,897	2,800	-	-
Cash distributions per unit	0.51	0.51	0.51	0.51	0.51	0.17	-	-

1) Total revenue reported is net of transportation expenses.
2) Net income and net income before discontinued operations and extraordinary items are the same.
3) The comparative quarterly results have been restated for the retroactive impact of adopting the accounting standard asset retirement obligations.

Crescent Point's revenue has increased significantly through the previous eight quarters primarily due to the corporate acquisitions of Tappit in September 2003 and Capio in January 2004, several property acquisitions over the past two years and the Trust's successful drilling program. The overall growth in the Trust's asset base also contributed to the general increase in cash flow from operations and net income. Capital expenditures fluctuated throughout this period as a result of the timing of acquisitions. The general increase in cash flows throughout the last eight quarters has allowed the Trust to maintain stable monthly cash distributions of $0.17 per unit.

Fourth Quarter Review

The following are the main highlights of the fourth quarter:

- Crescent Point's cash flow from operations increased by 66 percent from $11,975,000 or $0.62 per unit-diluted in the fourth quarter of 2003 to $19,875,000 or $0.64 per unit-diluted in the fourth quarter of 2004, primarily due to the accretive acquisitions completed in the year, increased production on existing properties and higher corporate netbacks.
- The Trust's acquisitions and successful drilling program increased average daily production by 55 percent from 7,331 boe/d in the fourth quarter of 2003, to 11,338 boe/d in the fourth quarter of 2004. Crescent Point exceeded its fourth quarter production target by more than 1,000 boe/d mainly due to its new pool discoveries at Manor-Auburnton and better than expected production performance at Little Bow, John Lake, Tatagwa and Sounding Lake.
- The Trust completed a property acquisition of approximately 370 bbl/d of high netback, light oil production in its core Sounding Lake area for a purchase price of $14,189,000.
- Crescent Point drilled 10 gross wells and 8.4 net wells in the fourth quarter with a success rate of 100 percent. Two new pool discoveries at Manor-Auburnton contributed to the record production achieved in the fourth quarter of 2004, with over 1,000 bbl/d of initial flush production.
- Crescent Point maintained an excellent balance sheet throughout the quarter which positions the Trust for continued growth in 2005 and beyond. The Trust's credit facility was increased to $135,000,000 and syndicated with two additional Canadian chartered banks.
- Crescent Point maintained consistent monthly distributions of $0.17 per unit, totaling $0.51 per unit for the fourth quarter of 2004, representing a fully diluted payout ratio of 80 percent.

Business Risks and Prospects

Crescent Point is exposed to several operational risks inherent in exploiting, developing, producing and marketing crude oil and natural gas. These risks include:

- Economic risk of finding and producing reserves at a reasonable cost;
- Financial risk of marketing reserves at an acceptable price given market conditions;
- Cost of capital risk to carry out the Trust's operations; and
- The risk of carrying out operations with minimal environmental impact.

Crescent Point strives to manage or minimize these risks in a number of ways, including:

- Employing qualified professional and technical staff;
- Concentrating in a limited number of areas with low cost exploitation and development objectives;
- Utilizing the latest technology for finding and developing reserves;
- Constructing quality, environmentally sensitive, safe production facilities;
- Maximizing operational control of drilling and producing operations;
- Mitigating price risk through strategic hedging; and
- Adhering to conservative borrowing guidelines.

Health, Safety and Environmental Policy

The health and safety of employees, contractors, visitors and the public, as well as the protection of the environment, is of utmost importance to Crescent Point. The Trust endeavours to conduct its operations in a manner that will minimize both adverse effects and consequences of emergency situations by:

- Complying with government regulations and standards;
- Conducting operations consistent with industry codes, practices and guidelines;
- Ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- Providing training to employees and contractors to ensure compliance with Trust safety and environmental rules and procedures;
- Promoting the aspects of careful planning, good judgment, implementation of the Trust's procedures, and monitoring Trust activities;
- Communicating openly with members of the public regarding our activities; and
- Amending the Trust's policies and procedures as may be required from time to time.

Crescent Point believes that all employees have a vital role in achieving excellence in environmental, health and safety performance. This is best achieved through careful planning and the support and active participation of everyone involved.

Outlook

Crescent Point's outlook for 2005 is as follows:

Production	
Oil and NGLs (bbl/d)	7,850
Natural gas (mcf/d)	15,000
Total (boe/d)	10,350
Cash flow ($000s)	82,000
Cash flow per unit-diluted ($)	2.55
Cash distributions per unit ($)	2.04
Payout ratio - per unit-diluted (percent)	80
Capital expenditures ($000s) (1)	26,000
Wells drilled, net	29.0
Pricing	
Crude oil - WTI ($US/bbl)	40.00
Crude oil - Corporate ($Cdn/bbl)	50.00
Natural gas - AECO ($US/GJ)	5.20
Natural gas - Corporate ($Cdn/GJ)	6.50
Exchange rate ($Cdn/$US)	0.80

(1) The projection of capital expenditures excludes acquisitions, which are separately considered and evaluated.

Additional information relating to Crescent Point, including the Trust's renewal annual information form, is available on SEDAR at www.sedar.com.

CORPORATE GOVERNANCE

Crescent Point is committed to the highest standards in its reporting to unitholders and regulatory agencies. Over the past year, there have been a number of new reporting policies and procedures established by the securities commissions and the Canadian Institute of Chartered Accountants. Crescent Point is committed to meeting and exceeding these new policies and procedures.

The Trust's Board of Directors (the "Board") is comprised of seven directors, the majority of whom are independent directors. The Board is responsible for overseeing the overall management of the business and affairs of the Trust. The Board holds regularly scheduled quarterly meetings with additional meetings scheduled to address specific topics as required. The Board has established an Audit Committee, a Reserves Committee, an Environmental, Health and Safety Committee and a Compensation Committee to assist in performing its duties.

The Audit Committee reviews quarterly and year-end disclosures and provides recommendations to the Board. The Reserves Committee reviews the year-end reserve evaluation prepared by independent engineers. The Environmental, Health and Safety Committee reviews Crescent Point's environmental programs and compliance with regulations. The Compensation Committee is responsible for assessing the performance of senior management and recommending reasonable compensation for senior management and directors.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The Management of Crescent Point Energy Trust is responsible for the preparation of all information included in this Annual Report. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly in all material respects. The financial information contained elsewhere in this Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management has developed and maintains an extensive system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the financial statements realistically report the Trust's operating and financial results, and that the Trust's assets are safeguarded. Management believes that this system of internal controls has operated effectively for the year ended December 31, 2004.

PricewaterhouseCoopers LLP, an independent firm of chartered accountants, was appointed by a resolution of the Board of Directors to audit the financial statements of the Trust and provide an independent professional opinion. PricewaterhouseCoopers LLP was appointed to hold such office until the next annual meeting of the unitholders of the Trust.

The Board of Directors, through its Audit Committee, has reviewed the financial statements including notes thereto with Management and PricewaterhouseCoopers LLP. The members of the Audit Committee are composed of independent directors who are not employees of the Trust. The Board of Directors has approved the information contained in the financial statements based on the recommendation of the Audit Committee.

Scott Saxberg
President and Chief Executive Officer
February 25, 2005

Greg Tisdale
Chief Financial Officer

AUDITORS' REPORT TO THE UNITHOLDERS

To the Unitholders of Crescent Point Energy Trust

We have audited the consolidated balance sheets of Crescent Point Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of operations and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta
February 25, 2005

CONSOLIDATED BALANCE SHEET

As at December 31 ($000)	2004	2003
		Restated (Note 3(b))
ASSETS		
Current assets		
Cash	44	82
Accounts receivable	20,645	17,505
Investments in marketable securities		188
Prepaids and deposits	339	318
	21,028	18,093
Deposits on property, plant and equipment		1,000
Reclamation fund (Note 8)	225	-
Property, plant and equipment (Note 7)	317,918	168,591
Goodwill (Note 6)	58,147	21,171
	397,318	208,855
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	20,322	13,945
Cash distributions payable	3,346	2,345
Bank indebtedness (Note 9)	92,720	40,220
Risk management liability (Note 14)	7,898	-
	124,286	56,510
Asset retirement obligation (Note 10)	21,403	5,195
Future income taxes (Note 12)	33,081	29,713
	178,770	91,418
Unitholders' equity		
Unitholders' capital (Note 11(b))	240,006	113,880
Exchangeable shares (Note 11(b))	7,406	10,782
Contributed surplus (Note 11(d))	1,918	339
Accumulated earnings	34,792	4,133
Accumulated cash distributions (Note 5)	(65,574)	(11,697)
	218,548	117,437
	397,318	208,855

Commitments (Note 15)

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board of Directors

Gerald A. Romanzin
Director

D. Hugh Gillard
Director

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

For the years ended December 31 ($000 except per unit amounts)	2004	2003
		Restated (Note 3(b)&(d))
REVENUE		
Oil and gas sales	155,299	76,792
Transportation expenses (Note 3(d))	(3,968)	(2,074)
Royalties, net of ARTC	(28,675)	(14,044)
Financial instruments		
Realized losses	(18,855)	(2,722)
Unrealized losses (Note 14)	(7,987)	-
	95,814	57,952
EXPENSES		
Operating	22,941	11,561
General and administrative	4,727	2,140
Unit-based compensation (Note 11(d))	2,294	339
Interest on bank indebtedness	3,398	1,640
Depletion, depreciation and amortization	40,157	19,187
Accretion on asset retirement obligation (Note 10)	798	178
Capital and other taxes	2,854	770
Reorganization costs	-	5,215
Gain on sale of investment (Note 4)	-	(313)
	77,169	40,717
Income before future income tax	18,645	17,235
Future income tax expense (recovery)	(12,014)	8,101
Net income for the year	30,659	9,134
Accumulated earnings, beginning of the year	3,994	3,117
Retroactive application of change in accounting policy (Note 3(b))	139	24
Transfer of assets pursuant to Plan of Arrangement (Note 6(c))	-	(8,142)
Accumulated earnings, end of the year	34,792	4,133
Net income per unit (Note 13)		
Basic	1.10	0.50
Diluted	1.09	0.50

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31 ($000)	2004	2003
		Restated (Note 3(b))
CASH PROVIDED BY (USED IN)		
OPERATING ACTIVITIES		
Net income for the year	30,659	9,134
Items not affecting cash		
Future income taxes	(12,014)	8,101
Unit-based compensation (Note 11(d))	2,294	339
Depletion, depreciation and amortization	40,157	19,187
Accretion on asset retirement obligation (Note 10)	798	178
Gain on sale of investment (Note 4)	(53)	(313)
Unrealized losses on financial instruments (Note 14)	7,987	-
Cash flow from operations	69,828	36,626
Asset retirement expenditures (Note 10)	(314)	-
Change in non-cash working capital		
Accounts receivable	(959)	1,583
Prepaid expenses and deposits	194	(219)
Accounts payable	(1,682)	(5,060)
	67,067	32,930
INVESTING ACTIVITIES		
Expenditures on petroleum and natural gas properties	(112,647)	(61,297)
Acquisition of Tappit Resources Ltd. (Note 6(b))	-	(7,714)
Acquisition of Capio Petroleum Corporation (Note 6(a))	(76,845)	-
Petroleum and natural gas deposits	1,000	2,225
Reclamation fund net contributions (Note 8)	(225)	-
Proceeds on sale of investments (Note 4)	241	741
Change in non-cash working capital		
Accounts receivable	275	(770)
Accounts payable	42	(1,972)
	(188,159)	(68,787)
FINANCING ACTIVITIES		
Issue of trust units, net of issue costs	122,037	42,685
Increase in bank indebtedness	51,893	2,521
Cash distributions (including DRIP)	(53,877)	(11,697)
Change in non-cash working capital		
Cash distributions payable	1,001	2,345
	121,054	35,854
INCREASE (DECREASE) IN CASH	(38)	(3)
CASH AT BEGINNING OF YEAR	82	85
CASH AT END OF YEAR	44	82

See accompanying notes to the consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2004 and 2003

1. CORPORATE REORGANIZATION AND BASIS OF PRESENTATION

Crescent Point Energy Trust (the "Trust") is an open-ended unincorporated investment trust created pursuant to a Declaration of Trust and operating under the laws of the Province of Alberta. The Trust was established as part of a Plan of Arrangement (the "Arrangement") that became effective on September 5, 2003.

The Arrangement gave effect to the transactions contemplated by the agreement entered into on May 26, 2003 by Crescent Point Energy Ltd. ("old Crescent Point" or the "Corporation") and Tappit Resources Ltd. ("Tappit"). The reorganization resulted in the shareholders of old Crescent Point and Tappit receiving trust units in the Trust, a new oil and natural gas energy trust that owns subsidiaries which own all of old Crescent Point's and Tappit's producing assets. In addition, the shareholders of old Crescent Point and Tappit received shares in a separate, publicly-listed, growth and exploration focused producer, StarPoint Energy Ltd. ("StarPoint").

Pursuant to the Arrangement, shareholders of both old Crescent Point and Tappit received shares of StarPoint, and at their election, either units of the Trust, which will pay monthly cash distributions, or exchangeable shares which may be exchanged into units of the Trust. The Arrangement also resulted in a share consolidation of the outstanding shares of old Crescent Point.

For each old Crescent Point Class A share owned, shareholders received at their election:
a) 0.5 units of the Trust and 0.5 shares of StarPoint, or
b) 0.5 exchangeable shares and 0.5 shares of StarPoint.

For each old Crescent Point Class B share owned, shareholders received at their election:
a) 0.75 units of the Trust and 0.75 shares of StarPoint, or
b) 0.75 exchangeable shares and 0.75 shares of StarPoint.

For each Tappit common share owned, shareholders received at their election:
a) 0.19 units of the Trust, $0.36 cash and 0.1 shares of StarPoint, or
b) 0.19 exchangeable shares, $0.36 cash and 0.1 shares of StarPoint.

Upon completion of the Arrangement, 16,433,734 Trust units and 2,000,000 exchangeable shares were outstanding. In addition, the Trust can issue up to 935,000 restricted units under the Restricted Unit Bonus Plan (see note 11(d)).

The Arrangement involving conversion to the Trust has been accounted for as a continuity of interests. Accordingly, these consolidated financial statements reflect the financial position, results of operations and cash flows as if the Trust had always carried on the businesses formerly carried on by old Crescent Point. All assets and liabilities are recorded at historical cost. The year ended December 31, 2003 reflect the results of operations and cash flows of old Crescent Point and its subsidiaries up to September 5, 2003, and the results of the Trust and its subsidiaries from September 5 to December 31, 2003.

The term "units" has been used in these financial statements to identify both the Trust units and exchangeable shares of the Trust issued on or after September 5, 2003 as well as the Class A common shares of the Corporation outstanding prior to the conversion on September 5, 2003. All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

2. SIGNIFICANT ACCOUNTING POLICIES

a) Principles of Consolidation
The consolidated financial statements include the accounts of the Trust and its subsidiaries. Any reference to "the Trust" throughout these consolidated financial statements refers to the Trust and its subsidiaries. All inter-entity transactions have been eliminated.

b) Joint Ventures
Certain of the Trust's exploration and production activities are conducted jointly with others through unincorporated joint ventures. The accounts of the Trust reflect its proportionate interest in such activities.

c) Property, Plant and Equipment
The Trust follows the full cost method of accounting for petroleum and natural gas properties and equipment, whereby all costs of acquiring petroleum and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Such costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling both productive and non-productive wells, related plant and production equipment costs and related overhead charges. Maintenance and repairs are charged against income, and renewals and enhancements which extend the economic life of the properties and equipment are capitalized.

Gains and losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would alter the rate of depletion by 20 percent or more.

Depletion, Depreciation and Amortization

Depletion of petroleum and natural gas properties is calculated using the unit-of-production method based on the estimated proved reserves before royalties, as determined by independent engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relevant energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proven reserves and excludes the unimpaired cost of undeveloped land. Costs associated with unproved properties are not subject to depletion and are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of impairment is added to costs subject to depletion.

Tangible production equipment is depreciated on a straight-line basis over its estimated useful life of 15 years. Office furniture, equipment and motor vehicles are depreciated on a declining balance basis at rates ranging from 10 percent to 30 percent.

Ceiling Test

A limit is placed on the aggregate carrying value of property, plant and equipment, which may be amortized against revenues of future periods (the "ceiling test"). The ceiling test is an impairment test whereby the carrying amount of property, plant and equipment is compared to the undiscounted cash flows from proved reserves using management's best estimate of future prices. If the carrying value exceeds the undiscounted cash flows, an impairment loss would be recorded in income. The impairment is measured as the amount by which the carrying amount of property, plant and equipment exceeds the discounted cash flows from proved and probable reserves.

d) Asset Retirement Obligation

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis when incurred, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the reserves. Revisions to the estimated timing of cash flows or the original estimated undiscounted cost would also result in an increase or decrease to the obligation and related asset.

e) Goodwill

The Trust must record goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired company. The goodwill balance is assessed for impairment annually at year-end or as events occur that could result in an impairment. Impairment is recognized based on the fair value of the reporting entity ("consolidated Trust") compared to the book value of the reporting entity. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust has been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the implied value of the goodwill. Any excess of the book value of goodwill over the implied value of goodwill is the impairment amount. Impairment is charged to earnings and is not tax effected, in the period in which it occurs. Goodwill is stated at cost less impairment and is not amortized.

f) Unit-based Compensation

The Trust established a Restricted Unit Bonus Plan on September 5, 2003. Prior to the Arrangement on September 5, 2003, the Corporation had a stock-based compensation plan.

The fair value based method of accounting is used to account for the stock options granted during the year ended December 31, 2003 and the restricted units granted under the Restricted Unit Bonus Plan. Compensation expense is determined based on the estimated fair value of stock options or trust units on the date of grant. The compensation expense is recognized over the vesting period, with a corresponding increase to contributed surplus. At the time the options or restricted units vest, the issuance of shares or units is recorded with a corresponding decrease to contributed surplus.

g) Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax base, using substantively enacted future income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust distributes all of its taxable income to the unitholders in accordance with the Trust indenture and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income taxes has been made in the Trust.

h) **Financial Instruments**

The Trust uses financial instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. Financial instruments that are not designated as hedges under CICA accounting guideline AcG-13 "Hedging Relationships" are recorded on the balance sheet as either an asset or a liability with the change in fair value from the prior period recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13, and, accordingly, has marked-to-market its financial instruments.

i) **Revenue Recognition**

Revenues associated with sales of crude oil, natural gas and natural gas liquids are recognized when title passes to the purchaser.

j) **Cash and Cash Equivalents**

Cash and cash equivalents include short-term investments with a maturity of three months or less when purchased.

k) **Measurement Uncertainty**

Certain items recognized in the financial statements are subject to measurement uncertainty. The recognized amounts of such items are based on the Trust's best information and judgement. Such amounts are not expected to change materially in the near term. They include the amounts recorded for depletion, depreciation and asset retirement costs which depend on estimates of oil and gas reserves or the economic lives and future cash flows from related assets.

3. CHANGES IN ACCOUNTING POLICIES

a) **Full Cost Accounting**

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-16 "Oil and Gas Accounting – Full Cost." The new guideline modifies how the ceiling test is performed, and requires cost centres to be tested for impairment using undiscounted future cash flows which are determined using management's estimate of future prices applied to proved reserves. If the carrying value exceeds the undiscounted cash flows, an impairment loss would be recorded in income. The impairment is measured as the amount by which the carrying amount of property, plant and equipment exceeds the discounted cash flows from proved and probable reserves.

There was no impact on the Trust's carrying amount for property, plant and equipment or to net income as a result of adopting this guideline. See Note 7 for additional information regarding the ceiling test.

b) **Asset Retirement Obligation**

Effective January 1, 2004, the Trust retroactively adopted the new accounting standard CICA Handbook section 3110 "Asset Retirement Obligations." This new section changes the method of accruing for costs associated with the retirement of fixed assets which an entity is legally obligated to incur. Previously, asset retirement obligations were accrued on an undiscounted unit-of-production basis over the entire life of the asset. The new accounting standard requires that companies record the fair value of legal obligations associated with the retirement of tangible long-lived assets. The obligations are recorded as liabilities on a discounted basis when incurred, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the reserves. Revisions to the estimated timing of cash flows or the original estimated undiscounted cost would also result in an increase or decrease to the obligation and related asset.

Upon adoption, all prior periods have been restated for the change in the accounting policy. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $5,195,000, an increase to property, plant and equipment of $3,443,000, an increase in accumulated earnings of $139,000, a decrease in the site restoration liability of $1,972,000 and an increase to the future tax liability of $81,000.

The previously reported 2003 amounts have been restated due to the retroactive application of this new standard. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $2,224,000, an increase to property, plant and equipment of $1,902,000, an increase in accumulated earnings of $24,000, a decrease in the site restoration liability of $363,000 and an increase to the future tax liability of $17,000. Net income for the year ended December 31, 2003 increased by $115,000 as a result of the retroactive application of the accounting standard.

There is no impact on the Trust's cash flow or liquidity as a result of adopting this new accounting standard. See Note 10 for additional information regarding the asset retirement obligation and impact on the consolidated financial statements.

c) **Financial Instruments**

Effective January 1, 2004, the Trust adopted the new CICA accounting guideline AcG-13 "Hedging Relationships." Financial instruments that are not designated as hedges under the guideline are recorded on the balance sheet as either an asset or liability with the change in fair value recognized in net earnings. The Trust has not designated any of its risk management activities as accounting hedges under AcG-13, and, accordingly, has marked-to-market its financial instruments.

The impact on the Trust's financial statements as at January 1, 2004 was the recognition of a risk management liability and a deferred financial instrument loss (net) of $3,209,000. The deferred financial instrument loss is being recognized in earnings as the contracts expire. See Note 14 for additional information regarding the financial instruments and risk management.

d) **Transportation Expenses**

Effective for fiscal years beginning on or after October 1, 2003, the CICA issued Handbook Section 1100 "Generally Accepted Accounting Principles," which defines the sources of GAAP that companies must use and effectively eliminates industry practice as a source of GAAP. In prior years, it had been industry practice for companies to net transportation charges against revenue rather than showing transportation as a separate expense on the income statement. Beginning January 1, 2004, the Trust has recorded revenue gross of transportation charges and a transportation expense on the income statement. Prior periods have been reclassified for comparative purposes. This adjustment has no impact on net income or cash flow.

4. INVESTMENTS IN MARKETABLE SECURITIES

In July 2003, the Corporation divested its entire investment of 2.15 million common shares in Rise Energy Ltd. ("Rise") subsequent to DT Energy Ltd. purchasing Rise. The carrying value had been written down to $0.20 per share in 2002. Net proceeds from the disposition amounted to $741,000.

5. RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust's indenture. To arrive at cash distributions, cash flow from operations, before changes in non-cash working capital, is reduced by reclamation fund contributions including, interest earned on the fund, and a portion of capital expenditures. The portion of cash flow withheld to fund capital expenditures is at the discretion of the Board of Directors.

($000, except per unit amounts)	2004	2003
Cash flow from operations before changes in non-cash working capital	69,828	36,626
Deduct		
Cash flow from operations before changes in non-cash working capital for January 1, 2003 to September 4, 2003	-	(21,221)
	69,828	15,405
Add (deduct)		
Cash withheld to fund current period capital expenditures	(15,412)	(3,708)
Reclamation fund contributions and interest earned on fund (1)	(539)	-
Cash distributions declared to unitholders	53,877	11,697
Accumulated cash distributions – beginning of year	11,697	-
Accumulated cash distributions – end of year	65,574	11,697
Cash distributions per unit (2)	2.04	0.68
Accumulated cash distributions per unit – beginning of year	0.68	-
Accumulated cash distributions per unit – end of year	2.72	0.68

1) The Trust implemented a reclamation fund effective July 1, 2004.

2) Cash distributions per unit reflect the sum of the per unit amounts declared monthly to unitholders.

6. ACQUISITIONS AND DISPOSITIONS

a) **Acquisition of Capio Petroleum Corporation**

On January 6, 2004, the Trust purchased all of the issued and outstanding shares of Capio Petroleum Corporation, a private oil and gas company. The purchase was paid for with cash and accounted for using the purchase method of accounting. The net assets acquired and consideration is allocated as follows:

	($000)
Net assets acquired	
Cash	56
Property, plant and equipment	61,688
Goodwill	36,976
Working capital deficiency	(5,862)
Asset retirement obligation	(575)
Future income taxes	(15,382)
Total net assets acquired	76,901
Consideration	
Cash	76,488
Acquisition costs (net of option proceeds of $2,580,000)	413
Total purchase price	76,901

b) **Acquisition of Tappit Resources Ltd.**

On September 5, 2003, old Crescent Point purchased all of the issued and outstanding shares of Tappit Resources Ltd., a public oil and gas company. The results of Tappit have been included in these financial statements from the date of acquisition. The transaction was accounted for as a business combination with net assets acquired and consideration allocated as follows:

	($000)
Net assets acquired	
Property, plant and equipment	73,223
Goodwill	21,171
Working capital deficiency	(1,948)
Bank debt	(23,699)
Asset retirement obligation	(830)
Future income taxes	(15,506)
Total net assets acquired	52,411
Consideration	
Cash	7,303
Units issued	44,698
Acquisition costs (net of option proceeds of $1,217,000)	410
Total purchase price	52,411

c) **Assets transferred to StarPoint Energy Ltd.**

Under the Arrangement on September 5, 2003, old Crescent Point transferred to StarPoint Energy Ltd. its existing interests in its British Columbia exploration area. A future tax liability has been recorded by the Trust as a result of transferring tax pools of $14,481,000, which were in excess of the net book value of $10,055,000. The details are as follows:

	($000)
Petroleum and natural gas properties and equipment	10,055
Future tax asset	1,587
Total assets transferred	11,642
Bank indebtedness assumed	3,500
Net assets transferred and reduction in accumulated earnings	8,142

7. PROPERTY, PLANT AND EQUIPMENT

2004 ($000)	Cost	Accumulated depletion, depreciation and amortization	Net
Petroleum and natural gas properties	305,955	57,169	248,786
Production equipment	74,752	7,216	67,536
Office furniture and equipment	2,662	1,066	1,596
	383,369	65,451	317,918

2003 ($000)	Cost	Accumulated depletion, depreciation and amortization	Net
Petroleum and natural gas properties	155,091	21,754	133,337
Production equipment	37,399	3,070	34,329
Office furniture and equipment	1,395	470	925
	193,885	25,294	168,591

At December 31, 2004, unproved land costs of $8,378,000 (2003 – $3,797,000) have been excluded from costs subject to depletion.

General and administrative expenses capitalized by the Trust during the year were $1,048,000 (2003 – $1,472,000).

The ceiling test calculation at December 31, 2004 indicated that the net recoverable amount from proved reserves exceeded the net carrying value of the petroleum and natural gas properties and equipment. The following are the prices that were used in the December 31, 2004 ceiling test:

	Average Price Forecast									
	2005	2006	2007	2008	2009	2010- 2012	2013	2014	2015	2016+[1]
WTI ($US/bbl)	42.00	40.00	38.00	36.00	34.00	33.00	33.50	34.00	34.50	2.0%
Exchange Rate	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	-
WTI ($Cdn/bbl)	51.22	48.78	46.34	43.90	41.46	40.24	40.85	41.46	42.07	2.0%
AECO ($Cdn/mcf)	6.60	6.35	6.15	6.00	6.00	6.00	6.10	6.20	6.30	2.0%

1) Percentage change represents the change in each year after 2015 to the end of the reserve life.

8. RECLAMATION FUND

A reclamation fund was established effective July 1, 2004 to fund future asset retirement obligation costs. The Board of Directors has approved contributions of $0.15 per barrel of production which results in minimum annual contributions of approximately $550,000 based upon properties owned at December 31, 2004. Additional contributions are made at the discretion of the Board of Directors. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distributions to the unitholders and cash withheld to fund current period capital expenditures. The following table reconciles the reclamation fund:

($000)	2004
Balance, beginning of year	-
Contributions	539
Actual expenditures	(314)
Interest earned on fund	-
Balance, end of year	225

9. BANK INDEBTEDNESS

On January 6, 2004, the Trust's revolving term demand bank loan facility was increased to $105,000,000. The amount available under the banking facility was temporarily increased to $117,000,000 for the period August 16 to October 7, 2004 in connection with the financing of three acquisitions. On October 7, 2004, the Trust's credit facility was increased to $135,000,000 and on November 1, 2004 the Trust's credit facility was restructured into a syndicated facility and two additional Canadian chartered banks were welcomed into the syndicate.

The interest charged on the facility is calculated based on a sliding scale ratio of the Trust's debt to cash flows. The effective interest rate for 2004 is 4.71% (2003 - 4.76%).

10. ASSET RETIREMENT OBLIGATION

The total future asset retirement obligation was estimated by management based on the Trust's net ownership in all wells and facilities. This includes all estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligation to be $21,403,000 at December 31, 2004 (December 31, 2003 - $5,195,000) based on total estimated undiscounted cash flows to settle the obligation of $47,448,000 (December 31, 2003 - $13,532,000). The expected period until settlement ranges from a minimum of two years to a maximum of 42 years, with the costs expected to be paid over an average of 20 years. The estimated cash flows have been discounted using a credit-adjusted risk-free rate of eight percent and an inflation rate of two percent.

The following table reconciles the asset retirement obligation:

($000)	2004	2003
Asset retirement obligation, beginning of year	5,195	2,224
Liabilities acquired through corporate acquisitions	575	830
Liabilities incurred	8,907	1,963
Liabilities settled	(314)	-
Changes in prior period estimates	6,242	-
Accretion expense	798	178
Asset retirement obligation, end of year	21,403	5,195

On July 1, 2004, the Trust implemented a reclamation fund. See Note 8 for information regarding the reclamation fund.

11. UNITHOLDERS' EQUITY

a) Authorized

Unlimited number of voting Trust units
2,000,000 exchangeable shares

b) Issued and outstanding

Refer to Note 1 – Corporate reorganization which discusses the Arrangement including old Crescent Point's share to unit reorganization.

The exchangeable shares can be converted at the option of the holder into Trust units at any time before September 5, 2013. Any exchangeable shares which have not been converted into Trust units by September 5, 2013 will automatically be converted into Trust units at that time. If the number of exchangeable shares outstanding reaches 1,000,000, the Trust can elect to redeem the exchangeable shares for Trust units. The number of Trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the distributions declared and the ten day weighted average Trust unit trading price preceding the monthly effective date. The exchangeable shares are not eligible for distributions, and are not publicly traded.

Effective with the November 2003 distribution, the Trust initiated a distribution reinvestment plan (the "Regular DRIP") and a premium distribution reinvestment plan (the "Premium DRIP"). The Regular DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95 percent of the average market price, as defined in the plan. The Premium DRIP permits eligible unitholders to elect to receive 102 percent of the cash the unitholder would otherwise have received on the distribution date. The additional cash distributed to the Premium DRIP unitholders is funded through the issuance of additional Trust units in the open market. Participation in the Regular and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the Regular and Premium DRIP plans.

	2004		2003	
Unitholders' Equity	**Number of shares/ Trust units**	**Amount ($000)**	**Number of shares/ Trust units**	**Amount ($000)**
Class A Shares				
Balance – January 1	-	-	23,978,092	34,335
Issued under the private placement	-	-	2,360,000	10,030
Issued to acquire properties	-	-	-	-
Issued under stock option exercise	-	-	1,607,499	2,049
Shares exchanged for Trust units	-	-	(25,130,464)	(41,738)
Shares exchanged for exchangeable shares	-	-	(2,815,127)	(4,676)
Balance – December 31	-	-	-	-
Class B Shares				
Balance – January 1	-	-	808,830	4,641
Shares exchanged for Trust units	-	-	(736,604)	(4,227)
Shares exchanged for exchangeable shares	-	-	(72,226)	(414)
Balance – December 31	-	-	-	-
Trust Units				
Balance – January 1	19,282,049	118,038	-	-
Units issued for Class A shares	-	-	12,565,232	41,739
Units issued for Class B shares	-	-	552,453	4,227
Units issued to Tappit shareholders	-	-	3,316,049	38,456
Issued for cash	8,150,000	110,663	2,650,000	31,800
Issued on conversion of exchangeable shares	661,727	3,376	98,598	550
Issued on vesting of restricted units [1]	45,630	487	-	-
Issued pursuant to the distribution reinvestment plans	1,109,335	16,031	26,616	318
To be issued pursuant to the distribution reinvestment plans	98,667	1,626	73,101	948
Balance – December 31	29,347,408	250,221	19,282,049	118,038
Cumulative unit issue costs	-	(10,215)	-	(4,158)
Total Unitholders' capital – December 31	**29,347,408**	**240,006**	**19,282,049**	**113,880**
Exchangeable Shares				
Balance – January 1	1,902,901	10,782	-	-
Units issued for Class A shares	-	-	1,407,563	4,676
Units issued for Class B shares	-	-	54,169	414
Units issued to Tappit shareholders	-	-	538,268	6,242
Exchanged for Trust units	(595,761)	(3,376)	(97,099)	(550)
Balance – December 31	1,307,140	7,406	1,902,901	10,782
Exchange ratio – December 31	1.19258	-	1.04219	-
Trust units issuable upon conversion – December 31	**1,558,869**	**7,406**	**1,983,184**	**10,782**

1) The amount of Trust units issued on vesting of restricted units is net of employee withholding taxes.

c) **Stock options**

Prior to the Arrangement, in accordance with the rules and policies of the Toronto Stock Exchange ("TSX"), the directors, management, employees and consultants of the Corporation could be granted options to acquire shares of the Corporation. The exercise price and vesting terms of any options granted were fixed by the Board of Directors of the Corporation at the time of grant, subject to the limitations of the TSX.

During 2003, there were 2,107,000 stock options outstanding, of which 1,607,499 were exercised, 5,001 were forfeited and 494,500 were cancelled. There were 494,500 options cancelled as these options were granted subject to the approval of the Toronto Stock Exchange. The Corporation made a cash payment to the holders of the cancelled stock options equivalent to the difference between the share trading price and the option price. The total payment was $1,941,000, of which $1,417,000 was expensed and $524,000 was capitalized. The stock option plan has been replaced by the Restricted Unit Bonus Plan (see note (11(d)). As a result of the change in the stock-based compensation plans, there were no stock options outstanding at December 31, 2003.

If the Corporation had used the fair value based method for stock options granted in the year ended December 31, 2002, an additional $588,000 of compensation costs would have been expensed in 2003, which would have reduced the Corporation's pro forma basic and diluted net income per unit to $0.46 in 2003.

d) **Restricted Unit Bonus Plan**

The Trust established the Restricted Unit Bonus Plan on September 5, 2003. Under the terms of the Restricted Unit Bonus Plan, the Trust may grant restricted units to directors, officers, employees and consultants. Restricted units vest at 33 1/3 percent on each of the first, second and third anniversaries of the grant date. Restricted unitholders are eligible for the first third of their monthly distributions for the first year, immediately upon grant. On the date the other two thirds of the restricted units vest, the restricted unitholders are entitled to the accrued distributions from the date of grant.

The unitholders have approved a maximum number of units allowable under the Restricted Unit Bonus Plan of 935,000 units. A summary of the changes in the restricted units outstanding under the plan is as follows:

	2004	2003
Restricted units, beginning of year	180,200	-
Granted	318,083	180,200
Exercised	(60,447)	-
Cancelled	(37,277)	-
Restricted units, end of year	400,559	180,200

The Trust recorded compensation expense and contributed surplus of $2,294,000 for the year ended December 31, 2004, based on the fair value of the units on the date of the grant.

12. INCOME TAXES

Effective April 1, 2004, the Alberta government enacted a reduction in provincial corporate income tax rates from 12.5 percent to 11.5 percent.

In 2003, Royal Assent was received, thereby legislating certain federal reductions in corporate income tax rates. The rate reductions are to be phased in over five years commencing in 2003. The rate changes incorporate a reduction in the applicable federal tax rate on resource income from 28 percent to 21 percent, provide for the deduction of crown royalties and eliminate the deduction for resource allowance. As a result of the rate changes, the Trust's future income tax rate decreased to approximately 35 percent in 2004 (36 percent in 2003) compared to the tax rate of 41 percent applicable for the 2004 income tax year (42 percent for 2003).

a) The tax provision differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before taxes as follows:

($000)	2004	2003
Income before income taxes	18,645	17,235
Statutory income tax rate	40.70%	41.86%
Expected provision for income taxes	7,589	7,215
Effect of change in corporate tax rates	(465)	(1,335)
Non-deductible crown charges	2,077	2,160
Resource allowance	(5,275)	(4,222)
Net income of the Trust and other	(15,940)	2,100
Non-deductible reorganization costs	-	2,183
Future income tax expense (recovery)	(12,014)	8,101

b) The future income tax liability is comprised of:

($000)	2004	2003
Property, plant and equipment net book value in excess of tax value	29,972	18,628
Asset retirement obligation	(4,855)	(1,738)
Financial instruments	(2,564)	-
Partnership deferral	18,171	14,813
Unit issue costs	(677)	(934)
Loss carryforward	(6,359)	(1,029)
Attributed Canadian royalty income	(607)	(27)
Future income tax liability	33,081	29,713

c) The following tax pools are available for future use as deductions from taxable income:

	2004			2003		
($000)	The Trust	Other Entities	Total	The Trust	Other Entities	Total
Intangible resource pools	25,701	155,968	181,669	24,815	54,838	79,653
Undepreciated capital cost	-	55,790	55,790	-	34,835	34,835
Loss carryforward (expire through 2009)	-	18,195	18,195	-	2,893	2,893
Unit issue costs	6,748	1,938	8,686	1,716	2,623	4,339
Attributed Canadian royalty income	13,686	5,278	18,964	3,388	214	3,602
Total tax pools	46,135	237,169	283,304	29,919	95,403	125,322

13. PER TRUST UNIT AMOUNTS

The following table summarizes the weighted average Trust units used in calculating net income per Trust unit:

	2004	2003 (2)
Weighted average Trust units/shares	26,204,295	16,413,279
Trust units issuable on conversion of exchangeable shares (1)	1,558,869	1,983,184
Weighted average Trust units/shares and exchangeable shares	27,763,164	18,396,463
Dilutive impact of restricted units/stock options	320,446	47,373
Dilutive Trust units/shares and exchangeable shares	28,083,610	18,443,836

1) The Trust units issuable on conversion of the exchangeable shares reflects the exchangeable shares outstanding at the end of the year converted at the exchange ratio in effect at the end of the year.

2) All pre-arrangement comparative share numbers have been adjusted for the consolidation of Class A and Class B shares.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments of the Trust that are included on the balance sheet are comprised of cash, accounts receivable, the reclamation fund and current liabilities.

a) **Fair values of financial assets and liabilities**
The fair values of financial instruments approximate their carrying amount.

b) **Credit risk**
A substantial portion of the Trust's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks.

c) **Risk management**
The Trust has entered into fixed price oil contracts and interest rate swaps to manage its exposure to fluctuations in the price of crude oil and interest rates on debt.

The following is a summary of all financial instrument contracts in place at December 31, 2004:

Fixed Price Oil Contracts	Weighted average volume (bbl/d)	Weighted average price ($Cdn/bbl)	Index
January 1, 2005 to December 31, 2005	3,450	43.37	WTI
January 1, 2006 to December 31, 2006	2,062	51.20	WTI

Interest Rate Swaps	Amount ($000)	Interest rate %
January 1, 2005 to February 15, 2005	8,000	4.20
January 1, 2005 to March 4, 2005	12,000	4.03

None of the Trust's commodity or interest rate contracts have been designated as effective accounting hedges. Accordingly, all commodity and interest rate contracts have been recorded on the balance sheet as assets and liabilities based on their fair values. The following table reconciles the movement in the fair value of the Trust's commodity and interest rate contracts for the year ended December 31, 2004:

	($000)
Risk management liability (net), January 1, 2004	3,209
Change in mark-to-market unrealized loss	4,689
Risk management liability (net), December 31, 2004	7,898

Upon implementation of the new hedge accounting guideline on January 1, 2004, the Trust recorded a deferred financial instrument loss of $3,407,000 and a deferred financial instrument gain of $198,000. The opening deferred financial instrument loss and gain are being amortized into income as the contracts are settled. At December 31, 2004, $3,369,000 of the deferred loss and $71,000 of the deferred gain have been amortized into income.

15. COMMITMENTS

At December 31, 2004, the Trust had contractual obligations and commitments for office space and equipment:

	($000)
2005	470
2006	484
2007	242
2008	-
2009	-

16. COMPARATIVE INFORMATION

Certain information provided for the previous period has been restated to conform to the current period presentation.

CORPORATE INFORMATION

DIRECTORS

Scott Saxberg [4]
Paul Colborne, Chairman [2][4]
Hugh Gillard [1][2]
Peter Bannister [1][3]
Ken Cugnet [3][4]
Greg Turnbull [2]
Gerald Romanzin [1][3]

1. Member of the Audit Committee of the Board of Directors
2. Member of the Compensation Committee of the Board of Directors
3. Member of the Reserves Committee of the Board of Directors
4. Member of the Health, Safety and Environment Committee of the Board of Directors

OFFICERS

Scott Saxberg
President and Chief Executive Officer

C. Neil Smith
Vice President, Engineering and Business Development

Greg Tisdale
Chief Financial Officer

Dave Balutis
Vice President, Geosciences

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BANKER

The Bank of Nova Scotia, Calgary, Alberta

AUDITOR

PricewaterhouseCoopers LLP, Calgary, Alberta

LEGAL COUNSEL

McCarthy Tétrault LLP, Calgary, Alberta

EVALUATION ENGINEERS

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta

INVESTOR RELATIONS

Registrar and Transfer Agent
Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings:

Olympia Trust Company
2300, 125 - 9 Avenue SE
Calgary, Alberta T2G 0P6
Tel: (403) 261-0900

Stock Exchange
Toronto Stock Exchange - TSX

Stock Symbols
CPG.UN

Investor Contacts

Scott Saxberg, President and Chief Executive Officer
Tel: (403) 693-0020

Greg Tisdale, Chief Financial Officer
Tel: (403) 693-0020

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bcf	Billions of cubic feet
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
bbls	Barrels of oil or natural gas liquids
bbl/d	Barrels of oil or natural gas liquids per day
GJ	Gigajoules
mmbtu	Millions of British Thermal Units
mbbls	Thousands of barrels
mmbbls	Millions of barrels
mboe	Thousands of barrels of oil equivalent
mmboe	Millions of barrels of oil equivalent
mcf	Thousands of cubic feet
mcf/d	Thousands of cubic feet per day
mmcf	Millions of cubic feet
mmcf/d	Millions of cubic feet per day
NGL	Natural gas liquids
WTI	West Texas Intermediate

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